

DETERMINATION OF FAVORABLE CONDITIONS FOR THE DEVELOPMENT OF A WIND POWER FARM IN PUERTO RICO

by

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ABSTRACT

Development of a wind farm in the east coast of Puerto Rico has the potential of being an attractive economic proposal. This is so because the best wind resource of Puerto Rico is located on its east shore. Reliable wind data is available for several sites on the east coast, but important information to evaluate the economic feasibility of the wind farm can only be estimated or is unavailable. For example, land values, an unclear permitting process, lack of a legal framework, and no precedent in the Island of a purchase power agreement for a wind generation project makes any economic evaluation an uncertain one.

Present Worth (PW) economic analysis is performed using estimates for unknown parameters. A sensitivity analysis is used to ascertain the variability of uncertain parameters and Monte Carlo simulation is performed to do financial risk assessment.

Our work demonstrates that a wind farm project in Puerto Rico will be a feasible project under the economic conditions we studied. A private investor could sell the electricity as low as \$0.0837/kWh, or \$0.0792/kWh with a tax incentive. Utilities could sell electricity as low as \$0.0673/kWh, or \$0.0648/kWh with a tax incentive. If the utility finance with bonds the price could sell at \$0.0554/kWh, and \$0.0549/kWh with a tax incentive.

Sensitivity analysis showed that a wind farm project is very sensitive to energy prices, energy production and the installation costs. Monte Carlo simulation showed that an utility company has less economic risk in this type of project compared with a private investor.

RESUMEN

El desarrollo de una finca de viento en la costa este de Puerto Rico tiene el potencial de ser una propuesta económica atractiva. Datos de viento confiables están disponibles para distintos lugares de la costa este, pero información importante para evaluar la posibilidad económica de una finca de viento solamente se puede estimar o no esta disponible. Por ejemplo, el valor de la tierra, el proceso confuso de obtener permisos y ningún precedente en la Isla de un contrato de compra de energía para un proyecto de generación eólica hace de una evaluación económica una incierta.

Un análisis económico de valor presente es realizado utilizando estimados de parámetros inciertos. El análisis de sensibilidad es utilizado para comprobar la variabilidad de los parámetros inciertos y la simulación Monte Carlo es realizada para evaluar el riesgo financiero.

Nuestro trabajo demuestra que una finca de viento en Puerto Rico es factible bajo las condiciones económicas que hemos estudiado. Un inversionista privado podría vender electricidad a \$0.0837/kWh, y a \$0.0792/kWh con un incentivo de impuestos. Compañías eléctricas podrían vender electricidad a \$0.0673/kWh, y con un incentivo a \$0.0648/kWh. Financiando con bonos la compañía podría vender a \$0.0554/kWh, y con incentivo de impuestos a \$0.0549/kWh.

El análisis de sensibilidad demuestra que una finca de viento es sensitiva a: el precio de la electricidad, producción de energía y costos de instalación. La simulación Monte Carlo mostró que una compañía eléctrica tiene menor riesgo económico en este proyecto comparado con un inversionista privado.

Dedicado a mi familia . . .

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1 INTRODUCTION

The welfare and socioeconomic development of the modern countries revolves around their energetic needs. It is important for modern countries to have a reliable electric power source with continuous capacity to provide all of the present and future demand for electric energy at a reasonable cost.

The island of Puerto Rico has a developing economy that is constrained by its electric energy needs, [Esser 2003, Ed. TVS 2004, Zerby and Gordillo 1996]. These energetic needs are approaching the capacity of the existing generating system due to the increase in population level in the island. Figure 1.1, [Esser 2003], shows a linear increase in the energy consumption in Puerto Rico during the last 12 years. The energy consumption of a country is directly related to its population level. It is desired that the additional electric power for Puerto Rico be derived from diverse, dependable, non-polluting sources appropriate for the environment and economy of the island, [SSEB 2001, Zerby and Gordillo 1996]. Electric power generated from wind turbines appears to be an attractive alternative for Puerto Rico.

Although there has been a number of wind measurement projects in Puerto Rico, [Alvarado 1979, Elliot et al. 1987, MC 1984, PWEI 1985, Wegley et al. 1986, Soderstrom 1989], and the wind data is publicly available, there has been no successful initiative to develop an eolic generation project on the island despite the high price of fossil fuel generated electricity (relative to US prices). A major obstacle has been the lack of a legal framework that clearly establishes a permitting process and facilitates the negotiation of a purchase power agreement. Another uncertainty is the assessment of land

value for the purpose of eolic generation since there is no experience on how to determine this value and land is a precious commodity on a relatively small and heavily populated island, [Ed. TVS 2004]. At the end, a financial risk assessment will be required by potential investors in order to evaluate the wind alternative to produce electricity.

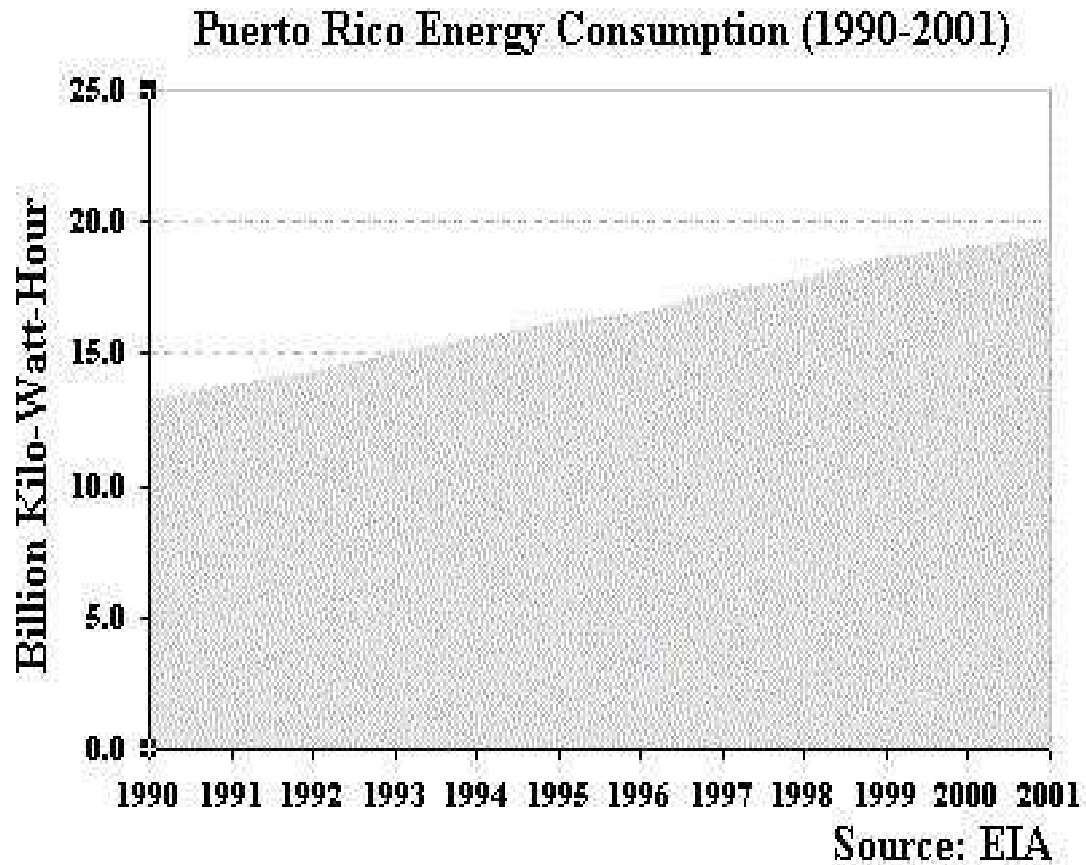


Figure 1.1: Puerto Rico Energy Consumption (1990-2001).

The objective of an economical analysis of a wind farm project is to determine whether the expected energy payments are sufficient to pay the debt on the project and provide an adequate rate of return. This thesis is an initial step in the economical analysis of eolic generation in Puerto Rico.

1.1 Topics of the Thesis

The title of this thesis is “Determination of Favorable Conditions for the Development of a Wind Power Farm in Puerto Rico”. The topic covers the area of analyzing wind data using the Weibull distribution and the project evaluation topic where a Present Worth economical analysis, sensitivity analysis, and Monte Carlo simulation for risk assessment are performed to evaluate a wind power farm project. In this document, a section is devoted to each of these models.

1.2 Objectives of the Thesis

The objectives of this work are:

1. Using available wind speed data, [Soderstrom 1989], for the East coast of Puerto Rico calculate mean wind speed using the Weibull distribution, and the arithmetic mean and cubic root cube methods, [Jangamshetti and Guruprasasa 1999, Jangamshetti and Guruprasada 2001, Raju et al.].
2. Calculate expected energy production for a given location in the East of Puerto Rico.
3. Using digital maps and satellite images develop two different wind turbine arrays, using two types of wind turbines, for the selected location.
4. Produce realistic cost estimates for such project.
5. Perform a complete present worth economical analysis including uncertainty sensitivity analysis and risk Monte Carlo simulation.

6. Calculate the price per kilo-watts-hour (kWh) for each array.
7. Suggest and quantify incentives that will make wind farm attractive to private developers. Examples of such measures could be:
 - ✓ Tax incentives
 - ✓ Net metering
 - ✓ Wheeling.

1.3 Summary of Following Chapters

The first chapter of this thesis provided an introduction to the work to be presented. The next chapter presents a literature review that includes previous work on this topic done in Puerto Rico. The third, fourth and fifth chapter presents the complete method used to accomplish the objectives of this thesis. Chapter 3 explains the probabilistic method used to evaluate wind data and determine the potential of a possible wind farm location. Chapter 4 shows the method to perform a complete economic evaluation of a project of this type. Chapter 5 shows the aspects that have to be considered when installing a wind farm. Chapter 6 shows the results and analysis of the base cases analyzed. And finally Chapter 7 presents the conclusions and recommendations of this thesis.

In Figure 1.2 we show a flowchart of the method used in this thesis. As shown in the flow chart the method is divided in three main topics: wind data analysis, economic analysis and wind farm sitting. The topics are discussed in that order although in practice, the sitting and wind data analysis of a wind farm may occur concurrently.

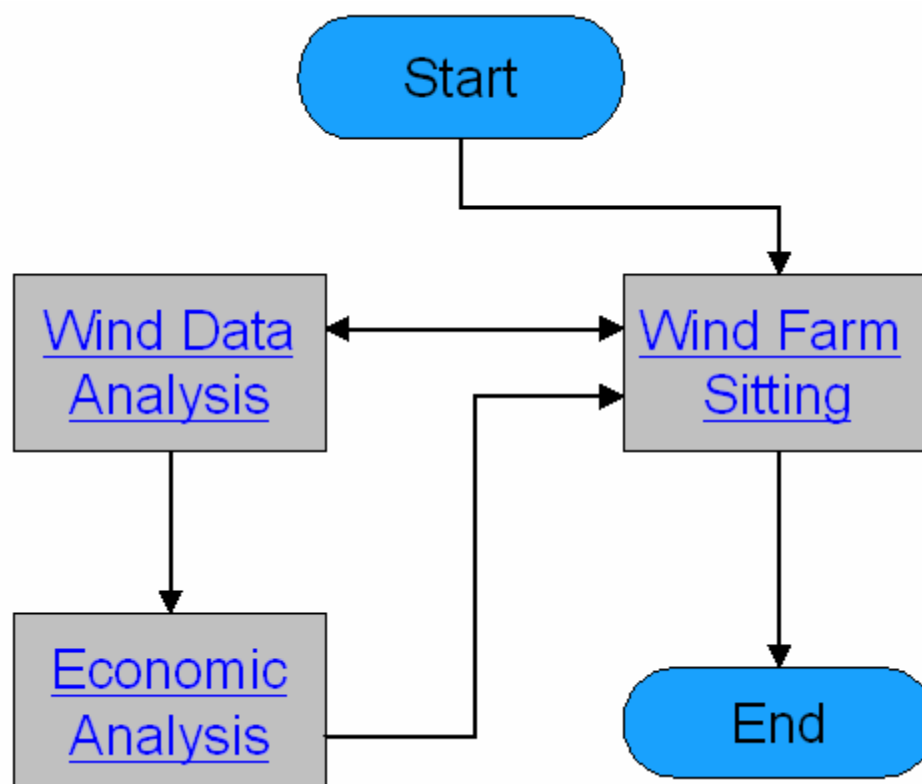


Figure 1.2: Method Flow Chart.

2 LITERATURE REVIEW: EOLIC GENERATION

2.1 History of the Wind Turbines

The wind had been used by humans for many centuries, [Johnson 2001]. The ancient explorers and merchants used the wind to propel their ships through the unexplored seas. Farmers used it to grind grain and pump water. In the case of the ships the energy of the wind was captured using sails strategically arranged in the ships hull. The kinetic energy of the wind was sufficient to overcome the friction of the water thus propelling the ships through the water. The farmers needed a more sophisticated device to grind grain and pump water; windmills. Windmills and wind turbines are synonymous. The blades, or airfoils, of the farmers' wind turbines captured the kinetic energy of the wind. This kinetic energy was transformed into rotational energy thus creating enough power to grind grain and pump water, [Johnson 2001].

By 1866 Charles Wheatstone and Wilhelm Siemens constructed electrical dc generators that would function even from a dead start and quickly build up to full capacity, [PSL]. With a few improvements, notably by the Belgian, Zenobe Gramme, availability of a self-excited dynamo made it practical to think of large-scale uses of electric power, [Katz 2003]. By the mid 1870s electric arcs were lighting the streets of Paris, London, New York, Cleveland and a host of other cities, [Williams 1999].

The invention of the electrical generator made possible that in 1890 Denmark became the first country to use wind for the generation of electricity. The Danes installed a 23 meter in diameter wind turbine, [Johnson 2001]. In 1925 the first wind turbines appeared

in the United States with ratings up to 3 kW, [Johnson 2001]. The first turbine to surpass the 1 MW rating was built in Grandpa's Knob in Vermont, U.S.A. The turbine was built in 1941 and had a rating of 1.25 MW at wind speeds above 13 m/s. It had a 34 m tower and a 53 m rotor diameter, [Johnson 2001].

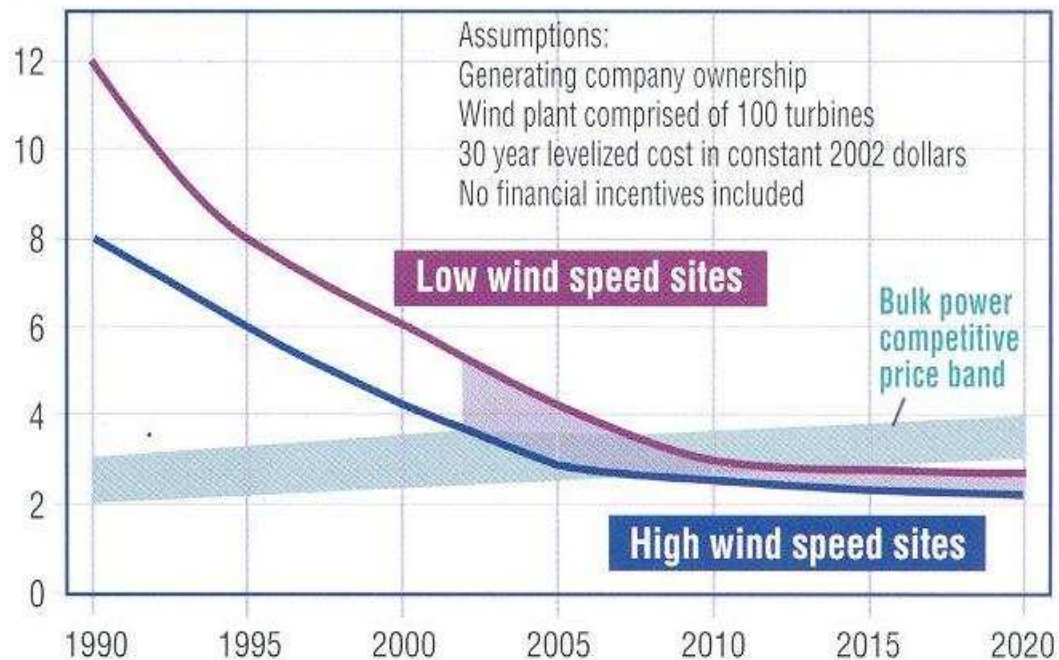
After World War II the price of oil in the U.S.A. dropped and interest in wind energy diminished. The oil embargo of 1973 was a wakeup call, and oil importing nations started looking at wind again. The United States chose a poor strategy to develop large-scale wind turbines by funding projects for test turbines. These turbines ranged from 100 kW to 2.5 MW and ran for brief periods of time. Once it was obvious that a particular design would never be cost effective, the turbine was quickly salvaged, [Johnson 2001].

On the other hand, Denmark established a plan that provided a revenue stream for small companies. They established a plan where landowners could buy a turbine and sell electricity to the local utility at a price where there was at least some hope of making money. They could try new ideas and learn from their mistakes. Denmark is the leader exporter of wind turbines. Vestas, a Dane company, has more installed wind turbines capacity worldwide than any other manufacturer, [Vestas].

The performance and price of wind turbines has dropped substantially in the last 30 years, [NREL 2003], due primarily to the increased turbine size, the research and development advances and the manufacturing improvements. It is possible to sell electricity produced by wind farms for a price of 4 cents per kilowatt hour as shown in Figure 2.1, [NREL 2003].

Cost of Wind Energy

Levelized Cents/kWh



The phenomenal growth experienced by the wind energy over the past decade can be attributed to a greatly reduced cost of energy.

Figure 2.1: Wind Energy Projected Costs for the Next 15 Years.

2.2 Wind Turbines

A wind turbine is a device for extracting kinetic energy from the wind. They work opposite to a fan. Instead of using electricity to make wind, like a fan, wind turbines use wind to generate electricity. The kinetic energy of the wind is transferred to the spinning blades that are attached to the rotor of the turbine. This rotor is usually connected through a shaft to a drive train that moves a generator. The generator transforms the kinetic rotational energy into electrical energy. Finally this electrical energy is processed

using power electronics technology and is sent to the customer through a transmission line. This is the case known as utility connected turbines.

There is also what is known as stand-alone systems. The stand-alone systems are usually of small capacity (less than 50 kW of total capacity) and they are not connected to the grid. Applications of these systems include powering small houses and farms, remote applications such as water pumping, telecom sites, ice-making, and powering villages, [NREL 2001, NREL 2003].

The most common turbines have a horizontal axis and three blades which are made of composite materials such as fiberglass. The turbines are mounted in a tower that is usually at least 40 m to 50 m long for utility scale generation wind turbines. The following Figure 2.2 shows the main components of a wind turbine.

The main components of the wind turbine are, [DWIA 2003, NREL 2004 and Stanwell]:

Anemometer: Measures the wind speed and transmits wind speed data to the controller.

Blades: Most turbines have either two or three blades that capture the wind and transfer the energy to the rotor hub. Wind blowing over the blades causes the blades to lift and rotate.

Brake: A disc brake located within the low speed shaft which can be applied mechanically, electrically, or hydraulically to stop the rotor in emergencies.

Controller: The controller starts up the machine at wind speeds above the cut-in speed and shuts off the machine at speeds above the cut-out speed. Turbines cannot operate at wind speeds above the cut-out speed because their generators could overheat. The controller is computer driven and also controls the yaw mechanism.

Gear box: Gears connect the low-speed shaft to the high-speed shaft and increase the rotational speeds from about 30 rotations per minute (rpm) to 1500 rpm, the rotational speed required by most generators to produce electricity. The gear box is the heaviest and one of the most costly parts of the wind turbine and engineers are exploring "direct-drive" generators that operate at lower rotational speeds and don't need gear boxes, [NREL 2004].

Generator: Usually an induction generator that produces 60 Hz AC electricity. The electricity is then stored, consumed locally, or sent along a transmission line for consumption.

High-speed shaft: Drives the generator. The shaft rotates at approximately 1500 rpm.

Low-speed shaft: The rotor turns the low-speed shaft at about 30 rpm.

Nacelle: Is the housing that protects the essential motorized parts of a turbine. The rotor attaches to the nacelle, which sits atop the tower and includes the gear box, low- and high-speed shafts, generator, controller, and brake. A cover protects the components inside the nacelle. Some nacelles are large enough for a technician to stand inside while working.

Pitch: Blades are turned, or pitched, out of the wind to keep the rotor from turning in winds that are too high (above cut-out speed) or too low (below cut-in speed) to produce electricity.

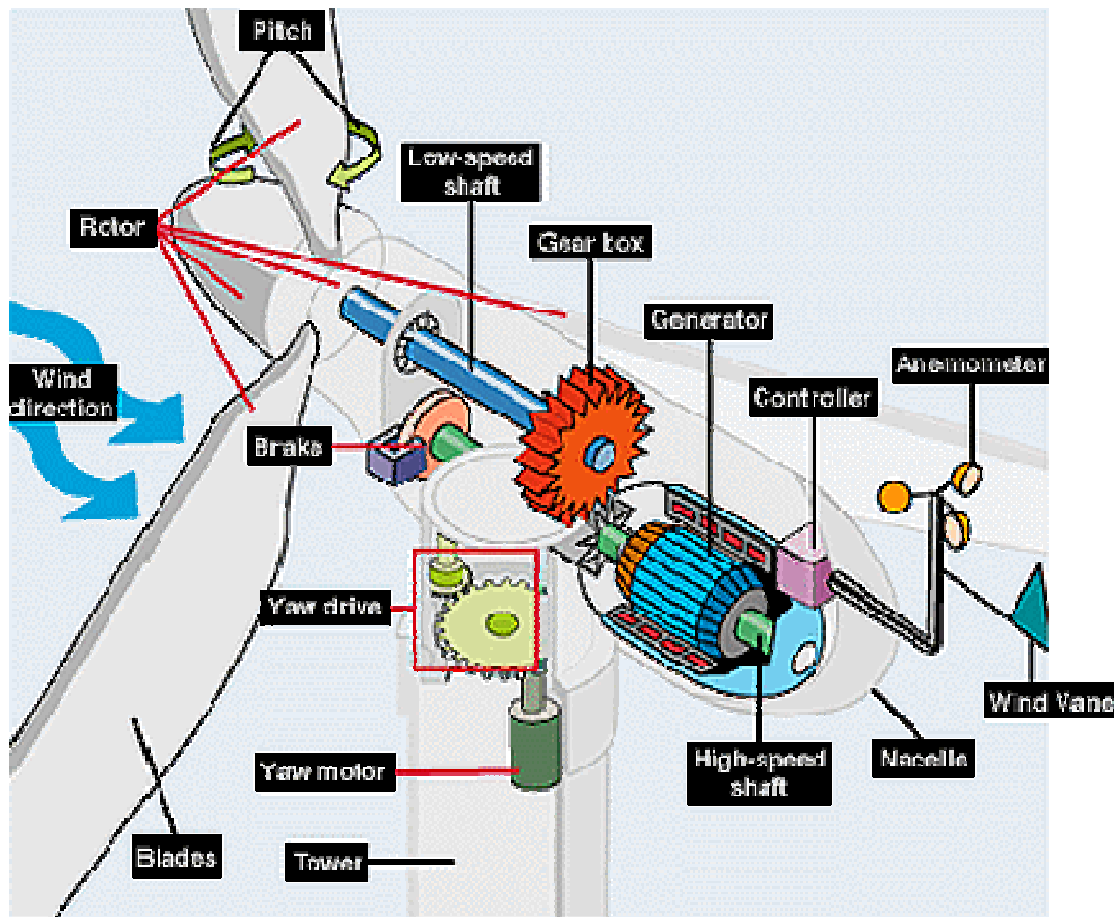


Figure 2.2: Main Components of a Wind Turbines, [20].

Generator: Usually an induction generator that produces 60 Hz AC electricity. The electricity is then stored, consumed locally, or sent along a transmission line for consumption.

High-speed shaft: Drives the generator. The shaft rotates at approximately 1500 rpm.

Low-speed shaft: The rotor turns the low-speed shaft at about 30 rpm.

Nacelle: Is the housing that protects the essential motorized parts of a turbine. The rotor attaches to the nacelle, which sits atop the tower and includes the gear box, low- and high-speed shafts, generator, controller, and brake. A cover protects the components

inside the nacelle. Some nacelles are large enough for a technician to stand inside while working.

Pitch: Blades are turned, or pitched, out of the wind to keep the rotor from turning in winds that are too high (above cut-out speed) or too low (below cut-in speed) to produce electricity.

Rotor: The blades and the hub together are called the rotor. The rotor drives the generator by harnessing the kinetic energy in the wind. The blades are aerodynamically shaped to best capture the wind. The amount of energy a turbine can capture is proportional to the rotor sweep area.

Tower: Towers for in-land turbines are made from tubular steel or steel lattice and constructed in a solid concrete base. Because wind speed increases with height, taller towers enable turbines to capture more energy and generate more electricity and avoid the turbulent air close to the ground.

Wind direction: Upwind turbines operate facing into the wind. Other turbines are designed to run downwind thus facing away from the wind.

Wind vane: Measures wind direction and communicates with the yaw drive to orient the turbine properly with respect to the wind.

Yaw drive: Upwind turbines face into the wind; the yaw drive is used to keep the rotor facing into the wind as the wind direction changes. Downwind turbines don't require a yaw drive; the wind blows the rotor downwind.

Yaw motor: Powers the yaw drive.

Wind turbines can be sited in-land (onshore) or offshore. This project will be based on in-land wind turbines. Figure 2.3, [NREL], shows onshore and offshore sited wind turbines.

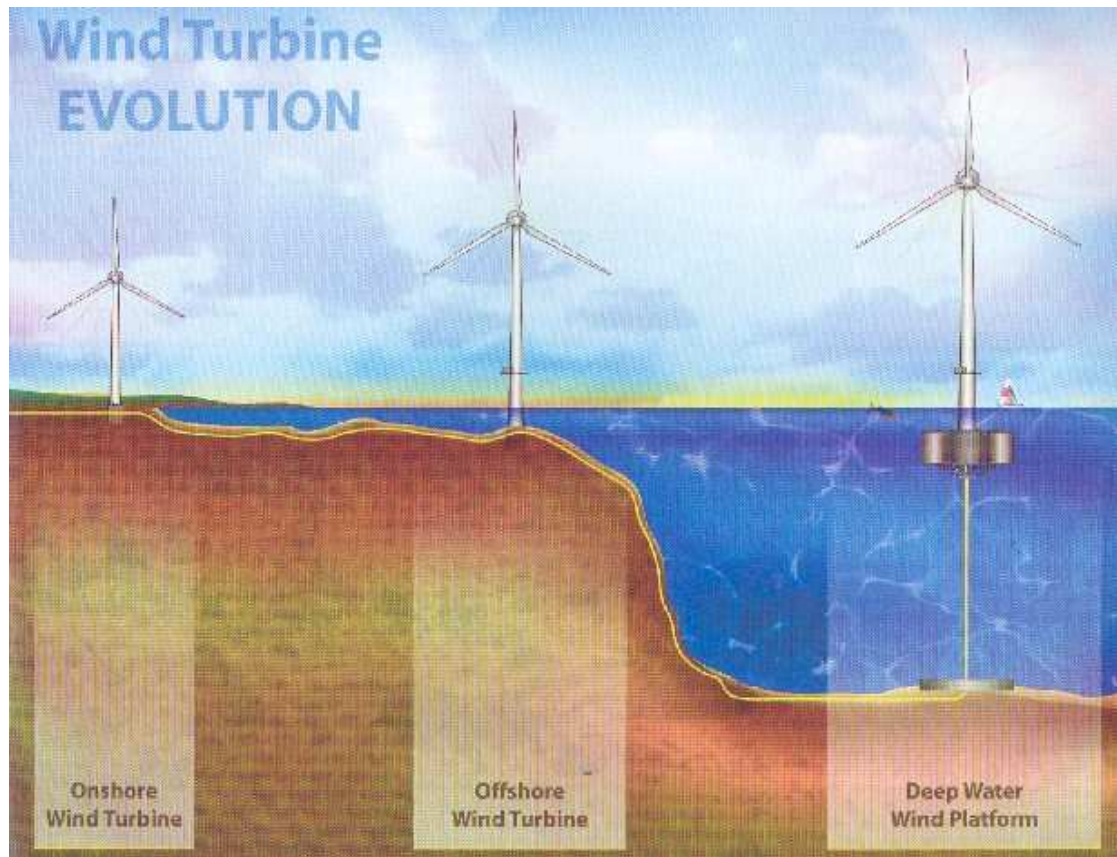


Figure 2.3: Common Sitting Location of a Wind Turbine.

2.3 The Energetic Potential of Wind

Wind energy projects can provide a cost effective and reliable form of producing energy. This form of generation can be used to provide energy to small villages, electric water pumps, stand-alone systems for homes, industries, hospitals and community centers. One of the problems is that good data of wind speed for the location where the

turbine is going to be installed is needed. Normally areas with good wind resource are identified as a first step to develop a wind farm project.

In the early 1980's various studies of wind speed in various regions of the United States were realized by the National Renewable Energy Laboratories (NREL), [Elliot 2002]. These studies were of limited use due to the lack of information about the variability of the wind. Currently NREL is producing wind maps with a high resolution of one square-kilometer (1 km^2) for any location in the world. To develop these wind maps NREL is using meteorological, analytical and computational models, [Elliot 2002]. The studies made by NREL and the creation of wind maps have facilitated the identifications of locations in the world with good wind resource.

The NREL studies include information of the magnitude and distribution of the wind in a specific region. These data is processed and the power density of the wind is obtained in watts per square-meter (W/m^2). This parameter is usually considered a better indicator of how good is the wind resource than the wind speed.

Wind turbine technology costs have been reduced significantly and, under the right conditions, wind can compete with coal, nuclear, and natural gas as a low cost source for producing energy in developed countries. In the United Kingdom there have been experiences with bids for wind farms where they have obtained a price of \$0.03/kWh, [Spencer 2002].

Where a monopoly exists in the electric power sector, i.e. where generation, transmission and distribution are bonded together, many times the electric utilities refuse to include renewable energy sources for generation claiming immaturity of the

technology, small size of renewable energy projects and fear of stability problems in the power system grid, [Spencer 2002].

2.4 Wind Energy Potential Around the World

2.4.1 Potential in China

China is a country that has been characterized by supplying their demand of electrical energy using coal. Only 345 MW of wind power are installed in China. This number is small compared with other smaller countries such as Germany and India. The Chinese have approximately 140,000 small turbines (1 kW to 3 kW). The only problem with this is that China although having an excellent wind resource all around the country the expected maximum power that can be generated using wind power is only around 250 GW. The other problem in China is that actually the wind power cost is the double of the cost of the power generated using coal. The reason for this is that the generation with wind is too small. To obtain cost effective results the private sector should have to obtain land in areas with a good wind resource and develop a project that utilizes big wind turbines with a rating at least of 1.5 MW, [Raufer and Wang 2002].

Nowadays, the best region for developing a wind farm in China is Guangdong. The government of China is very interested in developing this region. The future of wind power in China is improving continually and it will continue to do so if the technology of the wind turbines improves and increase their generation capacity, [Raufer and Wang 2002].

2.4.2 Potential in India

In India the generation of power using wind has gained attention and has been well accepted compared with other sources of renewable energy. India actually has 1,340 MW of wind power capacity installed.

India has made great efforts to make wind measurement studies and had determined that they have a maximum capacity of 45 GW. The Indian private sector had shown a lot of interest in the wind energy projects. The biggest installation that India has is 500 MW. There are 12 wind turbine manufactures in India with technology that permits them to fabricate wind turbines up to 750 kW.

After India obtained their independence it transformed from an agricultural economy to an agricultural-industrial economy. Industrial activities require great quantities of energy and India lack of fossil fuels. For this reasons the search for renewable sources like wind has been a necessity. Wind energy in India is economic and has a high performance.

In India the private sector is receiving economic incentives for making studies related to wind such as identifying places for future development and connection points to the electrical grid. India has a bright future in wind power and is willing to take the first place in the world as a producer of wind power, [Bakshi 2002].

2.4.3 Potential in the United Kingdom (UK)

Rapid development of British wind turbines manufacturing capabilities has reduced the generation costs for wind power in the last years, [Swift-Hook]. British machines are

now being sold to California at prices around £800¹ (British pounds) per installed kilowatt with warranties on performance and reliability. On sites with good wind in the U.K. these prices correspond to generation costs around 2 pence² per kWh, considerably cheaper than other methods such as coal or nuclear power which would cost around 3 pence per kWh.

2.4.4 Potential in France

With a hydro-power production of 65 TWh (2000), France is one of Europe's leading renewable energy producers. However, concerning wind energy, the power installed in July 2001 amounted to only 80 MW, [Belhomme 2002]. The French goal was to achieve 250 to 500 MW of installed wind power by the year 2005. Fifty-five (55) potential projects have been selected between 1997 and 2000, for a total power capacity of 361 MW. However, according to the recently adopted European Directive on the promotion of electricity from renewable energy sources the target for France in 2010 is to produce 21% of its demand from renewable sources. This represents an increase of about 6% with respect to 1997. On the other hand, the French Government has clearly shown its intention to further promote the development of wind energy, [Belhomme 2002]. Special purchase tariffs were fixed for wind power in December 2000 and an announcement had been made to have an additional 5000 MW of installed wind power by the year 2010. As a consequence of these incentives, a significant expansion of wind energy in France is expected to take place in the near future.

¹ £1.00 = \$1.76

² 1.00 pence = £0.00417 = \$0.00735

2.4.5 Potential in the United States

At the end of 2003 it was estimated that the U.S.A. has an installed capacity of 6,374 MW. The state of California is the leader with an installed capacity of 2043 MW followed by Texas with 1293 MW, [CEC 2001, AWEA 2000].

2.4.6 Potential in Denmark

The Danes have the biggest offshore wind farm in the world. It is located in place called Horns Rev to the west coast of the country. The depth of the water is between 5 and 15 meters. The farm consists of 80 wind turbines with a capacity of 2 MW each for a total capacity of 160 MW. This wind farm produces 2% of the consumed electric power in Denmark.

2.5 The Potential of Wind Energy in Puerto Rico

2.5.1 Puerto Rico's Energy Policy

A new energy policy for the Commonwealth of Puerto Rico was announced on December 22, 1993, [SSEB 2001, Zerby and Gordillo 1996]. Factors within the context of Puerto Rico's physical, social, and economic environment were considered while developing the policy and five areas of concern were identified:

- Efficient distribution of electrical energy.
- Use of fuels other than oil.
- Increased use of renewable technologies to generate electricity.
- Modification of construction regulations.

- Public education.

This energy policy addressed the need for energy and identified potential energy sources. The sources were categorized into short-, medium-, and long-term options for application based on their feasibility for Puerto Rico. The renewable energy technologies were categorized as long-term solutions.

Renewable energy technologies are considered new in Puerto Rico although there are renewable technologies in operation for more than 50 years in different locations around the world. The point of view of the Puerto Rico's Electric Power Authority (PREPA) is that takes a long time to develop new energy technologies from early research to commercialization. Issues concerning the design, cost, safety, operating and technical procedures to maximize reliability, appropriate maintenance procedures, and development of appropriate infrastructure and transportation for the new technologies all affect the ultimate commercialization of potential energy sources.

Puerto Rico, is considering various renewable and non-renewable energy technologies that can contribute to meet some of the projected 1,200 MW of future electric power demand. None of these technologies is likely to meet that demand by itself. The most important of these technologies are:

- Fossil fuels such as coal, natural gas and oil. Non-Renewable
- Biomass. Renewable
- Wind power. Renewable
- Solar energy. Renewable
- Hydroelectric energy. Renewable.

Puerto Rico's Public Policy on Energy excludes nuclear energy as an alternate source of energy for the island. Wind is a renewable energy source. The kinetic energy of the wind is directly transformed into electrical energy using a wind turbine and a generator. The disadvantage of wind is that it has a low energy density compared with the fossil and nuclear fuels, [Zerby and Gordillo 1996]. Not every available land space to install a wind farm is adequate to do so. The available wind speed and the duration of it have to be considered. An area with sustained windy conditions and available land space is the most appropriate to install wind turbines. Of the energy used in 1992 in the United States less than one percent was based on commercial-scale wind facilities.

Wind power in Puerto Rico may be feasible on small scale using state-of-the-art wind turbines. Land availability constraints and practical physical access to acceptable sites may limit the overall applicability of this technology in Puerto Rico. Wind power through the United States is rated on a scale of one to seven based on wind speed and power density, [Zerby and Gordillo 1996, NREL 2003]. The classification is shown in Table 2.1, [NREL 2003].

Table 2.1: Standard Wind Power Classification.

Wind Power Classification				
Wind Power Class	Resource Potential	Wind Power Density at 50m (W/m²)	Wind Speed at 50m (m/s)	Wind Speed at 50m (mph)
1	Poor	< 200	< 5.6	< 12.5
2	Marginal	200 – 300	5.6 – 6.4	12.5 – 14.3
3	Fair	300 – 400	6.4 – 7.0	14.3 – 15.7
4	Good	400 – 500	7.0 – 7.5	15.7 – 16.8
5	Excellent	500 – 600	7.5 – 8.0	16.8 – 17.9
6	Outstanding	600 – 800	8.0 – 8.8	17.9 – 19.7
7	Superb	800 – 1600	8.8 – 11.1	19.7 – 24.8
Wind speeds are based on a Weibull k value of 2.0				

The exposed points and capes along the north coast of Puerto Rico, as well as most of the east coast and the windward coast of Culebra, Vieques, and Mona Islands, have Class 3 winds. Cape San Juan on the northeast coast have class 4 winds. The high-peaks and the ridges of the central mountains have class 3 winds, with isolated peaks having class 4 winds. Figure 2.4 shows the wind map for Puerto Rico made by the National Renewable Energy Laboratories (NREL).

Developmental factors, such as environmental acceptance, consistency with existing land uses such as agriculture, and planning flexibility (short construction lead time and benefits associated with the modular nature of the wind farm) promote renewable energy use in Puerto Rico.

In 1996 a company named Kenetech had a standing proposal to provide up to 75 MW of wind power in Puerto Rico in three phases of 25 MW, and PREPA was also seeking wind energy projects from other companies, [Zerby and Gordillo].

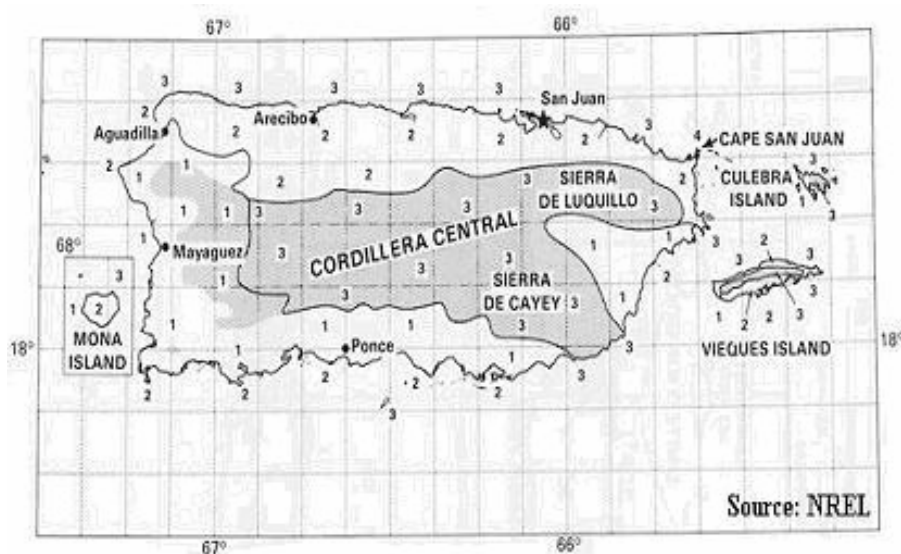


Figure 2.4: Puerto Rico Wind Map: Annual Average Wind Power, [30].

2.5.2 Previous Wind Measurements in Puerto Rico

Wind speed and direction has been measured at airports, primarily by the U.S. Weather Bureau, and universities all around the island of Puerto Rico, [Soderstrom 1989]. These measurements are done at the standard level used in airports around the world, an elevation of 10 meters above ground level. Measurements for wind farms should be made at least at heights of 30 meters. Therefore these measurements do not help much for the purpose of installing wind farms.

In December of 1984 Meridian Corporation submitted a report to the Puerto Rico Office of Energy, [Meridian 1984, Sodertsrom 1989]. The report contained wind data measured during a 15 month period. Of the seven measurement stations only three collected data for more than 50 days. The station that collected the most data was located at Cerro Maravilla in Jayuya, Puerto Rico. The measured data doesn't help to install a wind farm, but the report served as a starting point to identify regions with the potential to become wind farms.

In 1981 the U.S.D.O.E. published the "Wind Energy Resource Atlas" for Puerto Rico and the U.S. Virgin Islands. This was a work based on historical data to identify wind energy potential throughout the area, [PWEI 1985, Soderstrom 1989].

In 1989 Dr. Kenneth G. Soderstrom of the University of Puerto Rico submitted the report "Wind Farm Assessment for Puerto Rico" to the Puerto Rico Office of Energy, [Soderstrom 1989]. The project was primarily funded by a grant from the U.S. Department of Energy, and on it probability functions to model wind speed were developed for 4 sites in P.R. These functions were then used, in conjunction with wind

turbines power curves to estimate annual electric generation. The sites were 1) CROEM a school located in Cerro Las Mesas in Mayagüez, 2) Cuyón a central mountain range in the municipality of Cayey, 3) Aguirre located on the south coast next to the Aguirre Power Plant in Arroyo, and 4) Fajardo a municipality located in the northeast of Puerto Rico. The map in Figure 2.5, [Soderstrom 1989], shows the location of the 4 sites. The results showed that Fajardo has the highest mean wind speed, followed by Cuyón and CROEM. This confirms, once again, that the east coast of Puerto Rico is the best region to develop a wind farm project. However, Cuyón, CROEM and Aguirre are not suitable for the development of a wind farm due to lack of space to install a wind farm.

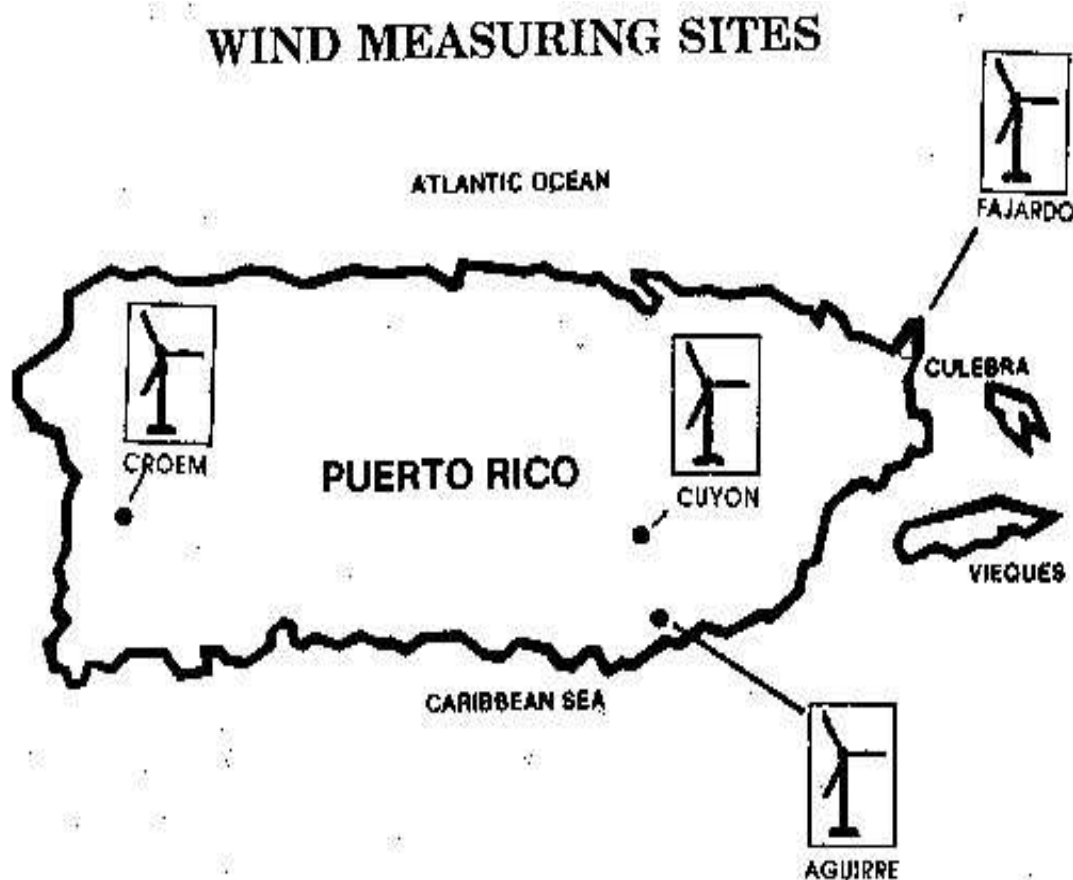


Figure 2.5: Map of Puerto Rico Showing the Wind Measuring Sites.

2.5.3 Previous Wind Energy Projects in Puerto Rico

Since the sixteenth century wind energy has been used in Puerto Rico. Windmills were used to grind sugar cane one of the principal products exported from the island during the colonization period. These windmills were located in the eastern coastal region of the island. This area is known to have the best wind resource in Puerto Rico, [Sodertsrom 1989].

Due to the oil crisis of 1973 the United States government increased their effort in the research and development of renewable energy sources. In the year 1978, a wind turbine with a capacity of 200 kW was installed in the small island of Culebra. Culebra is one of the 78 municipalities of Puerto Rico. Culebra is east of the Island of Puerto Rico and west of the island of St. Thomas, United States Virgin Islands (U.S.V.I.). This wind turbine was installed under the Federal Wind Energy Program, a joint effort between the National Aeronautics and Space Agency (N.A.S.A), the United States Department of Energy (U.S.D.O.E.) and the Puerto Rico Electric Power Authority (P.R.E.P.A.). The objective of this project was to demonstrate that wind energy could be used for the generation of electrical energy that was injected into the local power grid. The data collected from this project was analyzed by Batelle's Pacific Northwest Laboratory, [PWEI 1985, Soderstrom 1989]. The results showed that Culebra is a feasible site for a wind farm. A consequence of this study is that the entire east coast of Puerto Rico should also make a feasible site for wind generation.

2.6 Economics

2.6.1 Introduction

The electric power industry is highly capital intensive. It is probably more capital intensive than any other sector, particularly in developing countries. The planning and proper financial and economic evaluation of projects is important for rationalizing investment and achieving economic efficiency, [Khatib 1996].

Wind energy avoids some external or societal costs associated with conventional resources. These costs are the trade deficit from importing foreign oil and other fuels, and the health and environmental costs of pollution. It has been shown that wind energy is a reliable resource that provides more jobs per dollar invested than any other energy technology, [EERE, AWEA].

Wind farm projects can't be developed if there is no an economical benefit. There would be no bank or money lender willing to loan money for this type of project is there is no an adequate minimum attractive rate of return (MARR), [Khatib 1997]. To develop a project investors need the guarantee of an appropriate incentive and the guarantee that there will be an adequate payback period. For this type of project the average payback period is 7 years.

The wind turbine technologies has evolved greatly in the last 20 years and the cost of energy from the wind has dropped by 85% to the point that the price of electrical energy produced is around 4 to 6 cents per kWh in places with proper conditions to install wind turbines, [NREL 2003, Flowers 2003]. These costs are competitive with the direct

operating costs of many conventional forms of electricity generation now. The prices are expected to drop even further over the next 10 years, [NREL 2003, Flowers 2003]. Incentives like the federal production tax credit and net metering provisions available in some areas improve the economics of wind energy, [Ramos 2003, Flowers 2003, Green].

2.6.2 Tax Incentives

The most influential factors on the price of wind generated electricity are the wind speed of the location, the land value, legal framework, and the loan agreement. In Puerto Rico there are no realistic incentives or tax deductions to reduce the capital costs of the project and thus promote a wind farm project.

The tax deduction (incentive) laws in Puerto Rico for wind farm project are inadequate. Puerto Rico Law 120 of October 31st, 1994, (“Código de Rentas Internas”) includes for agricultural business the deduction of the capital costs used for the acquisition of a wind turbine. In the case of a corporation or society it is permitted a deduction of 50% up to \$3,000 of the capital costs, incurred during any taxable year, in the acquisition of a wind turbine and all its accessories to generate electricity if the turbine is manufactured in Puerto Rico. If the turbine is manufactured elsewhere the law allows a deduction of up to 50% of the added cost by local manufacturing. This incentive is geared toward very small wind turbines.

A Federal incentive known as the Production Tax Credit (PTC) applies to P.R. The PTC was included as part of the Energy Policy Act of October 24, 1992. The PTC is codified as Section 45 of the Federal Internal Revenue Code and if new legislation is not passed by the U.S. congress it will end December 31st, 2003. The PTC consists of a tax

credit of 1.5¢ per kWh (value of 1992) of production. This value is adjusted using the cost index or inflation factor for the year in which the energy sale is made, [AWEA, Ramos 2003]. The incentive is given for the first 10 years of operation of any given project. The only installations that qualify for this incentive are the ones that sell electricity to unrelated parties. The U.S. congress is considering a project to modify the PTC. One of these projects is to extend the PTC to the year 2007, but eliminating the inflation adjustments, [AWEA, Ramos 2003].

The Congress approved in 1992 the Renewable Energy Production Incentive (REPI) that also applies to Puerto Rico. The REPI has the objective of making a direct payment to public entities equivalent to the credit of the PTC. The REPI depends of the availability of annual funds appropriated by the Congress, [Ramos 2003].

2.6.3 Power Purchase Agreement

The Public Utilities Regulatory Policy Act of 1978 (PURPA), established that any qualifying individual can install a wind generator and the local electric utility must purchase the excess power, power not used by the owner, produced. PURPA intended to create a market for clean, renewable, electric-generating technologies by guaranteeing a buyer for the excess power, [UCS, EPSA]. With PURPA, small power producers meeting specific criteria are guaranteed purchase and interconnection. Many states now permit net metering, in which the utility must buy wind power generated by homeowners at the same retail rate the utility charges. Net metering allows the customer's meter to turn backward while wind energy is supplied to the grid by their wind turbine.

Based on reference [OFE 2003] PURPA does apply to the electric power utilities in Puerto Rico.

3 WIND DATA ANALYSIS

In this chapter the method to analyze wind data will be discussed. It is essential to analyze the available measurements of wind in a region before taking the step of suggesting a wind farm in such location. It is impossible to have an economically feasible project without good wind speeds available to power the wind turbines.

3.1 Wind Data Analysis Using Probability Density Functions

The power available in the wind varies with the cube of the wind velocity as expressed by Equation 3.1, [Patel 1999, DWIA 2003, Jangamshetti and Guruprasada 1999, Burton et al. 2001],

$$P = \frac{1}{2} \rho v^3 A \quad 3.1$$

Where, P is the power in watts, A is the area, in meters, through which the wind is passing, ρ is the density of the air 1.225 kg/m³ at 15.55 oC and 101,325 Pa, and v is the speed of the wind in meters per second.

If the measurement of wind speed was not made at the wind turbine hub height it is necessary to adjust the measured wind speed to the hub height. This can be done using the one-seventh power law as shown in Equation 3.2, [DWIA 2003, González 1998].

$$\frac{v(z_2)}{v(z_1)} = \left(\frac{z_2}{z_1} \right)^\alpha \quad 3.2$$

Where $v(z_2)$ is the wind speed at the desired height z_2 , $v(z_1)$ is the wind speed measured at a known height z_1 , and α is a coefficient known as the wind shear exponent. The wind shear exponent varies with pressure, temperature and time of day, but it has been commonly measured at one-seventh (1/7).

It is critical to have a precise measure of the wind speed for the location where wind turbines will be installed. A 10% deviation on wind speed turns into a 27% to 33% deviation on available power. For example, say the wind velocity at a given location is estimated as 11 m/s but the actual velocity is 10 m/s. Power at 11 m/s is 1331 W and at 10 m/s is 1000 W. This translates into a significant economical loss. Since wind velocity varies it is necessary to capture this variation in the model used to predict energy production. This is usually done using probability functions to describe wind velocity.

A probability density function is used to model the wind velocity variation, [Patel 1999, Jangamshetti and Guruprasada 2001]. A probability density function (pdf) is a curve related to a continuous random variable, X . The probability that X is less than a specified value, x , is the area under the pdf curve up to the point x . Other function used in this analysis is the cumulative distribution function (CDF). The CDF for any value x gives the cumulative probability associated with a probability distribution function. Specifically, a CDF gives the area under the probability density function, up to the value you specify. In other words, for any value x , CDF is the probability that a random variable has a value less than or equal to x . And finally the inverse cumulative probability gives the value associated with a given cumulative probability between 0 and

1. The PDF is used when it is known x and is desired to know the corresponding y value on the curve. The CDF is used when it is known x and is desired the value of the area under the curve. And the inverse CDF is used when it is known the cumulative area under the curve and is desired to know the x value.

PDFs are intended to reflect the probability that an event will occur between two end points. The area under the curve between any two speeds greater than zero will equal the probability that wind will blow somewhere between those two speeds. It is important to understand that actual height and shape of a pdf curve are determined such that the area under the curve from 0 to infinity is exactly 1. Physically, this means that there is a 100% chance that the wind will blow at some speed between 0 m/s and infinity m/s. Visually it is easier to physically interpret a CDF because it shows directly in the vertical axis the probability that the wind speed will be between two given wind speeds.

The Weibull probability distribution has been found to be a very accurate model to describe wind velocity variation. This distribution is often used in wind energy engineering, as it conforms well to the observed long-term distribution of mean wind speeds for a range of sites, [RETSCREEN]. The Weibull pdf is found in the literature using different notations. In this thesis the Weibull probability density function is defined as, [Montgomery and Runger 1998, Jangamshetti and Guruprasada 1999],

$$f(x) = \frac{\beta}{\eta} \left(\frac{x}{\eta} \right)^{\beta-1} e^{-\left(\frac{x}{\eta} \right)^{\beta}} \quad \text{where } 0 \leq x, \beta > 1, \eta > 0 \quad 3.3$$

The parameter β is known as the shape³ factor, and the parameter η is known as the scale⁴ factor. In wind probability analysis, the variable x is substituted by the variable v , which is a vector of the wind speeds at the place under study.

The effect of the shape factor (β) is reflected in the shape of the Weibull distribution. A lower shape factor indicates a relatively wider wind speed distribution around the average, while a higher shape factor indicates the opposite, [RETSCREEN]. A Weibull pdf with a shape factor bigger than one reflects the shape of a bell. The scale (η) factor defines where the bulk of the distribution lies and how stretched out the distribution is.

The cumulative distribution function (cdf) is obtained integrating the pdf, [Montgomery and Runger 1998], as shown in the following equation,

$$F(x) = \int_0^{\infty} f(x)dx = 1 - e^{-\left(\frac{x}{\eta}\right)^{\beta}} \quad \text{where } 0 \leq x, \beta > 1, \eta > 0 \quad 3.4$$

3.2 Weibull Parameter Estimation

3.2.1 Weibull Parameter Estimation Using Weibull Probability Plots

To obtain the values of the shape and scale parameters is necessary to draw the probability plot of the given data. The probability plot is a plot of estimated cumulative probabilities versus the data, though both variables may be transformed to induce linearity.

³ The shape factor is also known as the k parameter.

⁴ The scale factor is also known as the c parameter.

To estimate parameters using probability plots it is necessary to select the correct probability paper. This paper is a special graph paper designed for the hypothesized distribution. Probability paper is widely available for the normal, lognormal, Weibull, chi-square and gamma distributions.

The steps to construct a probability plot are the following:

1. Arrange the observations or data from smallest to largest. The sample should be arranged as x_1, x_2, \dots, x_n , where x_1 is the smallest observation and x_n is the largest observation.
2. Make a hypothesis by selecting a probability distribution that may be an adequate fit to the recorded data.
3. The ordered x_i observations are then plotted against their observed cumulative frequency on a probability paper corresponding to the assumed probability distribution selected in step #2. In the case of wind the Weibull distribution has proven to be an adequate model. Figure 3.1, [Reliasoft 2000] shows an example of a Weibull probability paper sheet.
4. Draw a straight line between the 25th and 75th percentile points in the probability plot. If the line reasonably falls above the data points the assumed distribution is an adequate model, otherwise the model is not appropriate.
5. To obtain the shape parameter β , a line parallel to the one obtained in step 3 has to be drawn through the slope indicator. The slope indicator is a scale at the top of the Weibull probability plot. The value at which this line intersects the slope indicator is the estimated shape parameter β .

6. Finally to estimate the scale parameter η , a horizontal straight line from the ordinate 63.2% has to be drawn, [Reliasoft 2000]. Then a vertical line has to be drawn from the point this line intersects the fitted straight line to the abscissa. The value at the intersection of the abscissa is the scale parameter η .

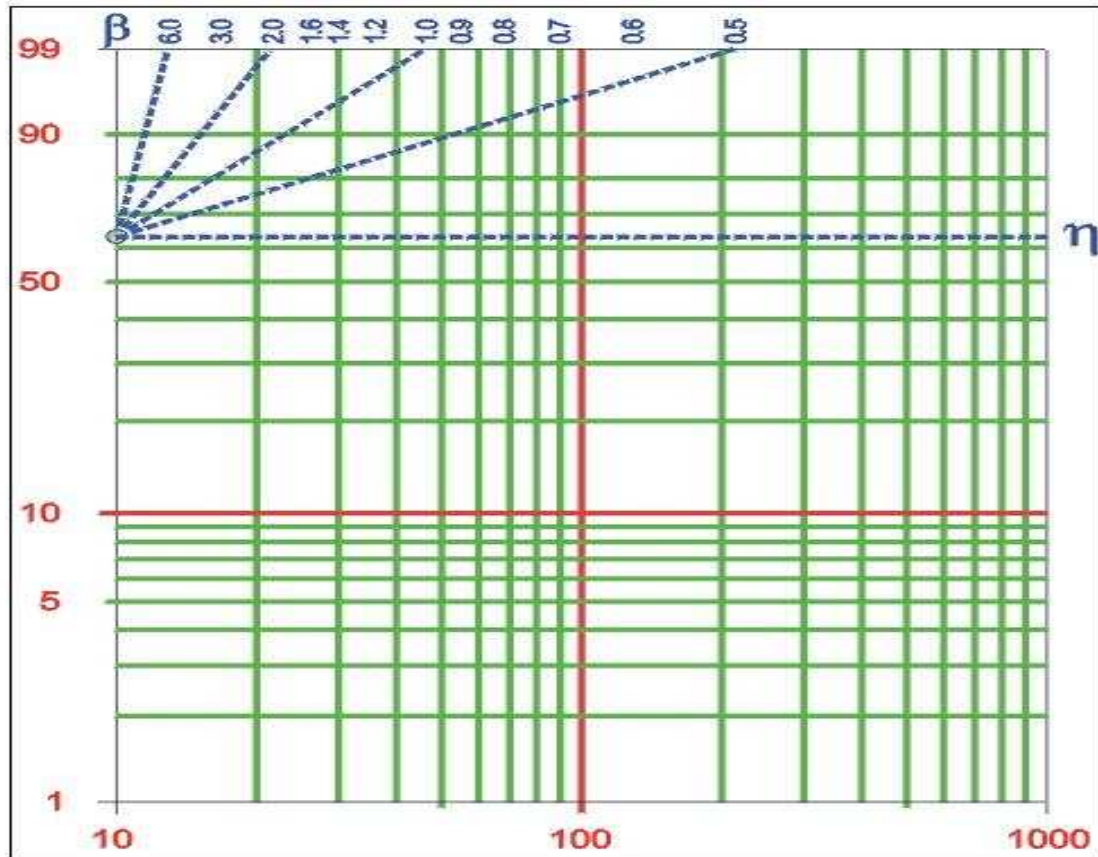


Figure 3.1: Example of Weibull Probability Plotting Paper.

3.2.2 Weibull Parameter Estimation Using Least Squares Parameter Estimation – Weibull Rank Regression in Y

Another method of estimating the shape and scale parameters is the Least Squares Parameter Estimation - Weibull Rank Regression in Y, [Reliasoft 2000]. Performing rank regression on Y requires that a straight line mathematically be fitted to a set of data

points such that the sum of the squares of the vertical deviations from the points to the line is minimized. This is in essence the same method as the probability plotting method, except that is mathematically based and we use the principle of least squares to determine the line through the points, as opposed to just "eyeballing" it. The procedure summarizes the method of the Weibull Rank Regression in Y.

First obtain their median rank plotting positions. Median rank positions are used instead of other ranking methods because median ranks are at a specific confidence level (50%). Median ranks can be found tabulated in many reliability books. They can also be estimated using the following equation, [Reliasoft 2000],

$$MR\% \sim \frac{i - 0.3}{N + 0.4} 100 \approx F(x_i) \quad 3.5$$

Where N is the total sample size, and i is the sample order number, and x is the data. In the wind data analysis x is the wind speed, N is the number of measurements made and i is a subscript used to identify the wind speed from the smallest value to its largest value. Now the parameter Y_i is calculated from, [Reliasoft 2000],

$$Y_i = \ln(-\ln(1 - F(x_i))) \quad 3.6$$

The Weibull pdf shape parameter, β , is calculated using, [Reliasoft 2000],

$$\beta = \frac{\sum_{i=1}^N (\ln x_i) Y_i - \frac{(\sum_{i=1}^N \ln x_i)(\sum_{i=1}^N Y_i)}{N}}{\sum_{i=1}^N (\ln x_i)^2 - \frac{(\sum_{i=1}^N \ln x_i)^2}{N}} \quad 3.7$$

The parameter a is used to calculate η and is found using, [Reliasoft 2000],

$$a = \frac{\sum_{i=1}^N Y_i}{N} - \beta \left(\frac{\sum_{i=1}^N \ln x_i}{N} \right) \quad 3.8$$

Finally the Weibull pdf shape parameter, η , is obtained substituting β and a in, [Reliasoft 2000],

$$\eta = e^{-(a/\beta)} \quad 3.9$$

3.2.3 Weibull Parameter Estimation Using Maximum Likelihood Estimators

The maximum likelihood estimation (MLE) method, from a statistical point of view, is considered to be the most robust of the parameter estimation techniques, [Reliasoft 2000]. Maximum likelihood estimation works by developing a likelihood function based on the available data and finding the values of the parameter estimates that maximize the likelihood function. The basic concept is to obtain the most likely values of the distribution parameters that best describe a given data. This can be achieved by using iterative methods to determine the parameter estimate values that maximize the likelihood function, but this can be rather difficult and time-consuming. Another method of finding the parameter estimates involves taking the partial derivatives of the likelihood function with respect to the parameters, setting the resulting equations equal to zero, and solving simultaneously to determine the values of the parameter estimates, [Reliasoft 2000, Montgomery and Runger 1998].

Table 3.1, [Reliasoft 2000] summarizes the properties that make the maximum likelihood method an attractive and excellent method to estimate the distribution parameters of a large sample, i.e. more than a hundred samples.

Table 3.1: Properties and Advantages of the MLE Method.

Property	Advantage
Asymptotically Consistent	As the sample gets larger, the estimates converge to the right values.
Asymptotically Efficient	For large samples it produces the most precise estimates.
Asymptotically Unbiased	For large samples one expects to get the right value on average.

The software MATLAB has a built-in function that easily calculates the Weibull pdf parameters using maximum likelihood estimation. The function `weibfit` estimates the parameters for a given input data vector. The results from MATLAB may differ from the ones obtained using the Rank Regression in Y because MATLAB uses a different expression of the Weibull pdf. The following equation is the Weibull pdf used by MATLAB as shown in the MATLAB help files.

$$f(x) = abx^{b-1}e^{-ax^b} \quad \text{where } 0 \leq x \leq \infty \quad 3.10$$

Comparing the standard Weibull pdf expression given in Equation 3.3 with the expression from Equation 3.10, the parameters of both can be related using the following equations:

$$a = \frac{1}{\eta^\beta} \quad 3.11$$

$$\eta = \sqrt[\beta]{\frac{1}{a}} \quad 3.12$$

$$b = \beta \quad 3.13$$

Where a is the scale parameter and b is the shape parameter for Equation 3.10.

3.2.4 Weibull Parameter Estimation Using Typical Shape Factor Values

A quick method to estimate the shape and scale parameters for the Weibull distribution is using typical values known for the shape factor. These typical values are known from experience and multiple observations of sites where wind speed measurements have been taken. These wind types are categorized as inland, coastal, and trade wind (off-shore) sites. Table 3.2, [RETSCREEN] shows typical values for the shape factor.

Table 3.2: Typical Shape Factor Values.

Type of Winds	Shape Factor ($\beta = k$)
Inland Winds	1.5 to 2.5
Coastal Winds	2.5 to 3.5
Trade Winds	3 to 4

Now the scale factor (η) can be calculated using the following equation, [Jangamshetti and Guruprasada 1999]:

$$\eta = \frac{\bar{v}}{\Gamma\left(1 + \frac{1}{\beta}\right)} \quad 3.14$$

Where \bar{v} is the average wind speed value and Γ is the gamma function, [Arfken and Weber 1985]. If there is sufficient wind speed measurements, i.e. 744 recorded speeds

(one for every hour in a 31 days month), the average wind speed can be estimated using the following equation:

$$\bar{v} = \left(\frac{1}{N} \sum_{i=1}^N v_i^n \right)^{\frac{1}{n}} \quad 3.15$$

Where \bar{v} is the actual wind speed measurement i , N is the total number of wind speed measurements, and $n = 1$ for arithmetic mean, $n = 2$ for root mean square, and $n = 3$ for cubic root cube.

3.2.5 Weibull Parameter Estimation Using Means, Standard Deviations and Justus Approximation

This method of parameter estimation can be used if the mean and standard deviation of the wind speed for a site are known. The mean wind speed and standard deviation can be calculated using the following equations, [Jangamshetti and Guruprasada 1999]:

$$\bar{v} = \left(\frac{\sum_{i=1}^N f_i v_i^n}{\sum_{i=1}^N f_i} \right)^{\frac{1}{n}} \quad 3.16$$

$$\sigma = \sqrt{\frac{\sum_{i=1}^N f_i (v_i - \bar{v})^2}{\sum_{i=1}^N f_i}} \quad 3.17$$

Where v_i is the actual wind speed measurement i , N is the total number of wind speed measurements, \bar{v} is the mean wind speed, f_i is the frequency of the measured wind speed

v_i , and $n = 1$ for arithmetic mean, $n = 2$ for root mean square, and $n = 3$ for cubic root cube.

Equations 3.14 and 3.18 can be solved simultaneously to obtain the values of the shape factor, β , and the scale factor, η , [Jangamshetti and Guruprasada 1999].

$$\sigma^2 = \frac{\bar{v}^2 \Gamma(1 + 2/\beta)}{\Gamma(1 + 1/\beta)} - 1 \quad 3.18$$

Solving simultaneously both equations can be difficult. An easier way to find the shape and scale factors is to solve for β using the Justus approximation, [Jangamshetti and Guruprasada 1999, Justus 1978], as shown in Equation 3.19.

$$\beta = \left(\frac{\sigma}{\bar{v}} \right)^{-1.086} \quad 3.19$$

Since β and \bar{v} are known Equation 3.14 can be solved for the scale factor η .

3.2.6 Weibull Parameter Estimation Using “The Quick Method”

From multiple observations we have found that for a large sample of wind speed measurements the shape and scale parameters can be estimated very accurately if we compare the estimation with the result that can be obtained using the more complicated and robust method of maximum likelihood estimators (MLE).

The “quick method” requires first to calculate the arithmetic mean wind speed, for a given large sample of wind measurements, using Equation 3.15. Then calculate the sample standard deviation using, [Montgomery and Runger 1998],

$$\sigma = \sqrt{\frac{1}{N-1} \sum_{i=1}^N (v_i - \bar{v})^2} \quad 3.20$$

Where v_i is the actual wind speed measurement i , N is the total number of wind speed measurements and \bar{v} is the arithmetic mean wind speed.

Now using Equation 3.19 Justus's approximation the shape parameter (β) can be calculated. Substituting the known quantities in Equation 3.14 the scale parameter (η) is calculated.

3.3 Calculating the Mean Wind Speed Using the Weibull PDF

3.3.1 Arithmetic Mean Wind Speed

The arithmetic mean wind speed it is what is normally known as the average wind speed. The arithmetic mean (average) wind velocity in meters per second is given by

$$V_{avg} = \int_0^{\infty} f(v)v dv = \int_{v_{min}}^{v_{max}} f(v)v dv \quad 3.21$$

Where $f(v)$ is the Weibull pdf, v is the measured wind speed data vector, v_{min} is the minimum wind speed measured and v_{max} is the maximum wind speed measured.

3.3.2 Cubic Root Cube Wind Speed

The use of arithmetic mean tends to underestimate the electric energy production. A case study made in Kappadaguda, India, [Patel 1999, Jangamshetti and Guruprasada

1999, Jangamshetti and Guruprasada 2001], suggests that the Cubic Root Cube (CRC) wind speed produces a better estimate of actual energy production.

To find the cubic root cube average speed the wind speed data vector is elevated to the cube and multiplied by the pdf. The function is integrated between v_{min} and v_{max} and then it is elevated to the one third (cubic root). The result is the cubic root cube (CRC) average speed in meters per second. The CRC average wind speed is given by

$$V_{CRC} = \sqrt[3]{\int_{v_{min}}^{v_{max}} f(v)v^3 dv} \quad 3.22$$

Where $f(v)$ is the Weibull pdf, v is the measured wind speed data vector, v_{min} is the minimum wind speed measured and v_{max} is the maximum wind speed measured.

3.4 Calculating the Expected Energy Production

3.4.1 Overview

After calculating the average wind speed the average power per unit of area available in the location of study can be calculated. The average power is normalized per unit area because rotor sweep area of the turbine varies with each turbine. The average power per unit of area available in the kinetic energy of the wind is given by,

$$\frac{P}{A} = \frac{1}{2} \rho v^3 \quad 3.23$$

Where v can be the arithmetic mean wind speed or the cubic root cube wind speed and A is the rotor sweep area. The unit of average power per unit area is watts/meter².

In this thesis we explain five methods to calculate the energy available to be captured by a wind turbine:

1. Integrating the Energy Probability Function
2. Substitution of Calculated Average Wind Speeds in the Energy Equation
3. Using the Wind Turbine Power Curve – Quick Method
4. Using the Wind Power Density
5. Producing Energy Curves Using Wind Turbine Power Curves

Of the four methods the most accurate is method #5: Producing Energy Curves Using Wind Turbine Power Curves. The reason for this is because it takes the unique characteristics of wind speed measurements for a site (the pdf shape and scale parameters), and the unique characteristics of a wind turbine (power curve, efficiency and rotor sweep area) and combines them to present a curve that shows the expected energy production for different arithmetic mean wind speed values in that site.

3.4.2 Calculating Energy Production Using the Energy Probability Function

The Energy Probability Function (epf) per unit of area is defined as,

$$\frac{e(v)}{Area} = \frac{1}{2} \rho v^3 f(v)(hours)(days) \quad 3.24$$

Where $e(v)$ is the epf, $f(v)$ is the Weibull pdf, Area is the rotor sweep area, and the product hours-days represents the number of hours in the period of analysis. The period of analysis can be a month or a year. The units of $e(v)$ are Wh/m²/m/s. The epf can be plotted and numerically integrated.

After plotting the epf the next step is to integrate the expression, as shown in Equation 3.25 in order to obtain the total energy for the given period. The Limits of integration are denominated by the minimum wind speed and the maximum wind speed measured.

$$\frac{E}{Area} = \int_{v_{min}}^{v_{max}} \frac{e(v)}{Area} dv \quad 3.25$$

If the result from Equation 3.25 is multiplied by the rotor sweep area of a given wind turbine, then total energy available during a period of time, it can be a month or a year, to be captured by a wind turbine is known. Betz law, [DWIA 2003], shows that 59% or less of the kinetic energy in the wind can be converted to mechanical energy using a wind turbine. Since the wind turbine is not 100% efficient the available energy to be captured, Equation 3.25, must to be multiplied by an efficiency factor to calculate the actual energy production in a site with a given wind turbine. In Section 3.4.4 we explain in more detail the disadvantages of this method.

3.4.3 Calculating Energy Production Using the Average Wind Speeds

The energy production can be calculated substituting the average (arithmetic or crc) wind speed in the average power per unit area equation (Equation 3.22). Multiplying the average power per unit area by the hours of the period the energy per unit of area available is calculated as shown in Equation 3.26.

$$\frac{E}{Area} = \frac{1}{2} \rho v^3 (days)(hours) \quad 3.26$$

Where E is the total energy and the Area is a constant. The variable v can be either the arithmetic mean wind speed or the cubic root cube wind speed, but using the crc wind speed the results from Equation 3.26 are similar to the results from Equation 3.25. This shows in principle that the crc wind speed is a better estimation of the average wind speed than the arithmetic mean wind speed.

Again wind turbines are not 100% efficient and the available energy must be multiplied by the efficiency of the turbine to calculate the actual energy production in a site for a given wind turbine.

3.4.4 Further Considerations of Calculating the Expected Energy Production Using the EPF or Average Wind Speed

As stated before the energy available in the wind is not the same energy that the wind turbine will capture. The wind turbine is limited by the Betz law, [Patel 1999, DWIA 2003]. German physicist Albert Betz explains that a wind turbine deflects the wind before it reaches its rotor plane causing a breaking effect in the wind. Betz' law says that only less than $16/27$ (or 59%) of the kinetic energy in the wind can be converted to mechanical energy using a wind turbine. This means that a wind turbine will only capture 59% or less of the wind energy that is bounded between its cut-in speed and its cut-out or furlong speed. The cut-in wind speed is the minimum speed at which the turbine can operate or produce energy and the cut-out speed is the maximum speed at which the turbine can operate or produce energy.

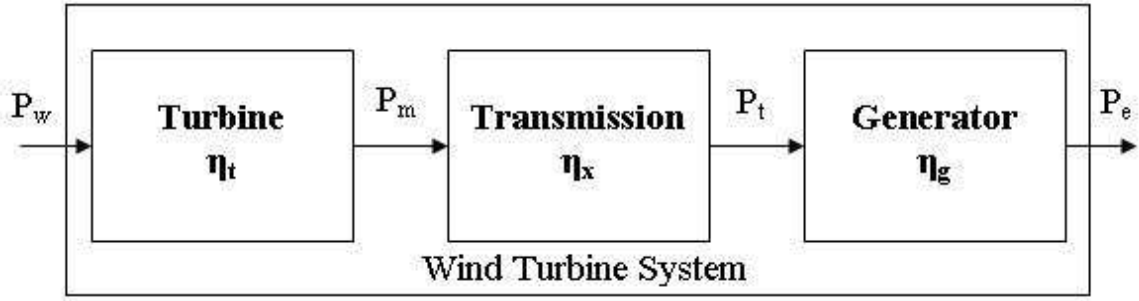


Figure 3.2: Typical Wind Turbine System.

Considering that a typical wind turbine, as shown in Figure 3.2, has three main components: turbine, transmission and generator. Each component has its own energy conversion efficiency. The turbine efficiency can be estimated to be around 40% to 50%. Transmission and generator efficiencies can be estimated to be around 80% to 90%. The wind turbine overall efficiency is known as the power coefficient and it can be derived from Figure 3.2,

$$P_m = \eta_t P_w \quad 3.27$$

$$P_t = \eta_x P_m \quad 3.28$$

$$P_e = \eta_g P_t \quad 3.29$$

Where P_w is the kinetic power available in the wind, P_m is the kinetic power converted in to mechanical power, P_t is the mechanical output power of the transmission, P_e is the electrical output power of the wind turbine generator, η_t is the turbine efficiency, η_x is the transmission efficiency and η_g is the generator efficiency.

Substituting Equations 3.27 and 3.28 in Equation 3.29 we obtain that the turbine power coefficients is given by

$$PC = \frac{P_e}{P_w} = \eta_t \eta_x \eta_g \quad 3.30$$

Where PC is the wind turbine power coefficient.

Is important to notice that since the turbine efficiency, η_t , has a maximum efficiency of 0.59 (59%) the ideal maximum value of the power coefficient will be 0.59. So assuming the case of a wind turbine with a turbine efficiency of 0.50, a transmission efficiency of 0.90, and a generator efficiency of 0.90 the power coefficient will be 0.41.

The power coefficient of a wind turbine is not a constant value. The power coefficient is a function of the wind speed. This can be easily observed plotting a graph of the turbine power coefficient versus the wind speed. To make the plot we can calculate the power coefficients using Equation 3.31.

$$PC_V = \frac{P_V}{1/2 \rho A V^3} \quad 3.31$$

Where PC_V is the power coefficient at wind speed V, P_V is the power curve rated output power at wind speed V, and A is the wind turbine rotor area. The difficult part of using Equation 3.31 is that wind turbine data sheets offer the values of the turbine output power for integer values of wind speed from $V = 1$ m/s to $V = 25$ m/s, but the fractions between the integers has to be estimated using linear interpolation or estimating it from the power curve.

To obtain the average power coefficient of a large sample first we have to obtain the power coefficient of each individual of the sample then using Equation 3.32 a weighted average value of the power coefficient is obtained,

$$PC_{avg} = \left(\frac{1}{N} \sum_{i=1}^N PC_i^n \right)^{1/n} \quad 3.32$$

Where PC_i is the power coefficient of wind speed measurement i , N is the total number of wind speed measurements, and $n = 1$ for arithmetic mean, $n = 2$ for root mean square, and $n = 3$ for cubic root cube.

At rated wind speed the wind turbine electrical power output is at its maximum, but the power coefficient is not. In most wind turbines power coefficient values are at it highest value, approximately 0.45 (45%), for wind speeds between 5 m/s and 10 m/s.

Based on the wind turbine limitations discussed above Equation 3.25 is rewritten as,

$$\left(\frac{E}{Area} \right)_{out} = \int_{vcin}^{vcout} \frac{e(v)}{Area} dv (PC_{avg}) \quad 3.33$$

Where $vcin$ is the turbine cut-in speed, $vcout$ is the turbine cut-out speed and PC_{avg} is the average cubic root cube power coefficient of the turbine. It is important to remember that the Area of the equation is the turbine rotor sweep area.

And equation 3.34 is rewritten as,

$$\left(\frac{E}{Area} \right)_{out} = \frac{1}{2} \rho v^3 (days)(hours)(PC_{avg}) \quad 3.34$$

Where v is the average wind speed and PC_{avg} is the average power coefficient of the turbine. If the average wind speed used is the arithmetic mean wind speed then the

arithmetic mean power coefficient is used, but is the cubic root cube wind speed is used then the cubic root cube power coefficient is used.

3.4.5 *Calculating Energy Production Using the Wind Turbine Power Curve*

A more direct way to calculate the energy production is using the wind turbine power curve. The power curve is a plot of output power vs. wind speed. It gives the output power of a wind turbine for any specific value of wind speed. The power curves vary with the turbine models and ratings, and are given by the manufacturer. The advantage of using a power curve is that it includes the power coefficient (PC), so there is no need to calculate it.

Using the turbine power curve data the average energy captured that can be obtained from the turbine can be estimated. The idea is to estimate the average output power at the average wind speed. Then the average output energy for a period of time is calculated using the following equation

$$E_{out} = P_{rated} (days)(hours) \quad 3.35$$

Where E_{out} is the energy captured and converted into electric energy (kWh), P_{rated} is the rated power in the power curve at the average wind speed calculated, and the product days-hours is the time period of analysis in hours.

There is a disadvantage of using this method. Looking for the output power directly from the graphic with out considering the shape and scale factor of the measured wind speed data can cause that the output power be underestimated or overestimated. Using the arithmetic mean wind speed the power output could be underestimated, and using the cubic root cube mean wind speed the power output could be overestimated.

3.4.6 Estimating Energy Production Using the Wind Power Density

A very efficient way of estimating the energy production without having to perform probability analysis is to calculate the Wind Power Density (WPD) as shown in Equation 3.36, [Patel 1999].

$$WPD = \frac{1}{2N} \sum_{i=1}^N \rho v_i^3 \quad 3.36$$

Where ρ is the density of the air in kg/m^3 , v_i is the wind speed of sample i in meters per second, and N is the number of measured samples. The units of the wind power density are W/m^2 .

The disadvantage of this method is that we need to calculate the average power coefficient to be able to obtain the yearly output energy using Equation 3.37.

$$E_{out} = WPD(days)(hours)(Area)(PC_{avg}) \quad 3.37$$

Where E_{out} is the yearly or monthly output power, PC_{avg} is the average cubic root cube power coefficient of the turbine and Area is the wind turbine rotor sweep area.

The density of the air in kg/m^3 can be calculated using the following equation,

$$\rho = \frac{P}{RT} \quad 3.38$$

Where P is the atmospheric pressure in Pa, R is the specific gas constant for air (287 J/kgK) and T is the temperature of the air in Kelvin degrees.

If the density of the air has to be adjusted to another height the following equation can be used,

$$\rho = \frac{353.05}{T} e^{-0.034\left(\frac{z}{T}\right)} \quad 3.39$$

where z is the height measured with respect to sea level, and T is the temperature at height z .

3.4.7 Producing Energy Curves to Estimate Energy Production

The energy curves method is the best to estimate energy production of a wind turbine for a specific site and for different values of average arithmetic mean wind speeds. The energy curves consist of plot of energy production versus arithmetic mean wind speed. The energy production can be easily obtain looking for the corresponding energy value for a given arithmetic mean wind speed.

One of the advantages of the energy curve is that since it is specific for a site a turbine from the energy curve we can obtain the optimum energy production values, i.e. at what arithmetic mean wind speed value the maximum energy is produced. Also the energy curve helps to show graphically the effect of the wind shear in the site, so we can decide to raise the hub height of the wind turbine if it is necessary to optimize the energy production.

Each energy production point of the energy curve is calculated using Equation 3.40, [RETSCREEN].

$$E_{\bar{v}} = (days)(hours) \sum_{v=1}^{25} P_v f(v, \beta, \eta_{\bar{v}}) \quad 3.40$$

Where $E_{\bar{v}}$ is the expected energy production in the site when the arithmetic mean speed is equal to \bar{v} , the product of days and hours gives the total hours in the period of

analysis, P_v is the turbine power output at wind speed v , and $f(v, \beta, \eta_{\bar{v}})$ is the Weibull probability density function for wind speed v , shape parameter β and scale parameter $\eta_{\bar{v}}$.

Is important to notice that for a given site the shape factor is constant, this means that if wind data is measured at a height of 10 meters and at 40 meters in the same point in space the shape parameter for both data should be the same, but the scale factor for the 40 meter data is higher than the scale factor of the 10 meter data.

Equation 3.40 can be solved for various values of \bar{V} , the value of $\eta_{\bar{v}}$ is updated using Equation 3.14 as discussed in section 3.2.4, and a plot of $E_{\bar{v}}$ versus \bar{V} is made to obtain the energy curve. Figure 3.3 presents a flowchart that explains how to create an energy curve.

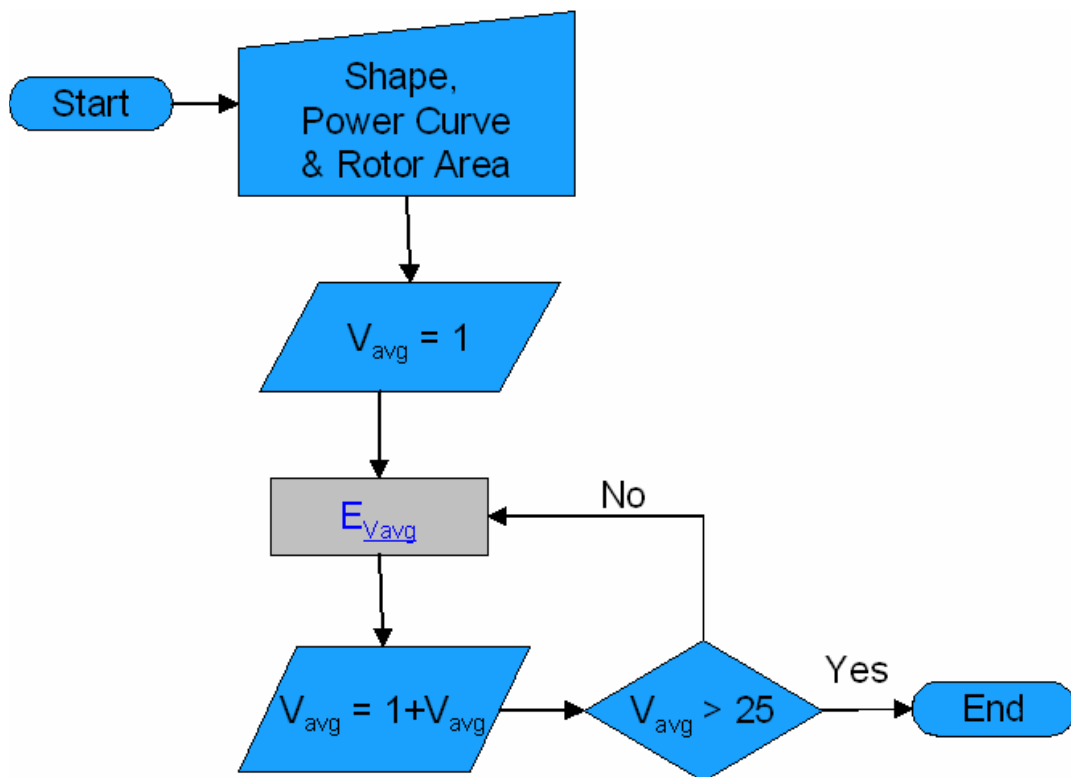


Figure 3.3: Flowchart to Create Energy Curve.

3.5 Concluding Remarks

In this chapter a method to analyze wind data was discussed. The method suggests alternatives to estimate the Weibull pdf parameters, calculate mean wind speed, calculate wind power density and estimate energy production for a given site.

A summary of the method used is:

1. Estimate the Weibull pdf parameters using the Maximum Likelihood Estimation (MLE) method. The MLE method is used in commercial software such as MATLAB and Mini Tab to estimate Weibull parameters.
2. Calculate the arithmetic and cubic root cube mean wind speeds.
3. Adjust wind speed results to the selected turbine hub height. Use the one-seventh ($1/7$) power law if there is no information about the wind shear exponent.
4. Use the cubic root cube mean wind speed to calculate the wind power density.
5. Produce an energy curve using the wind turbine power curve and rotor area, and the site shape parameter information.
6. Using the arithmetic mean wind speed look in the energy curve for the estimated yearly energy production and average power.

This method permits to estimate energy production for a given site before performing an economic analysis to determine the feasibility of a wind farm project.

4 ECONOMIC ANALYSIS

Without an economic analysis an engineering project can not be made a reality. Economics are the most important part related to the installation of a wind farm. One of the objectives of this thesis project is to provide a start up tool to estimates the costs and evaluate alternatives of installing a wind farm in Puerto Rico and determine under what conditions the project is viable.

The analysis is based on the present worth method. The present worth method is the method that PREPA used to evaluate the alternative solution for engineering projects, for example a Battery Energy Storage System (BESS) back in 1990, [Daly 1995].

4.1 The Net Present Worth (NPW) Method

4.1.1 Definition

The present worth (PW) or net present worth (NPW) method is used to compare different economical alternatives. It is defined as follows:

“A determination of the present worth (PW) involves the conversion of each individual cash flow to its present worth equivalent and the summation of the individual present worth to obtain the net present worth.” , [Canada et al. 2004]

The most important part of using the present worth is to know the relations available to move cash sums in time to the present. The following notation is used:

- i = effective interest rate or rate of return per interest period
- n = number of compounding periods

- g = geometric increase or decrease rate
- P = present sum (equivalent worth) of money
- F = future sum (equivalent worth) of money
- A = end-of-period cash flows in a uniform series continuing for a specified number of periods
- G = uniform period-by-period increase or decrease in cash flows or amounts (arithmetic gradient)
- G_g = geometric period-by-period increase or decrease in cash flows or amounts (geometric gradient)

If the present worth under a minimum attractive rate of return (MARR) is positive or zero, then the project is acceptable, otherwise not.

In section 4.1.2 to section 4.1.5 we present the equations to obtain the present worth of a given quantity in a cash flow. These equations can be found in any basic engineering economics book such as [Newman et al. 2004].

4.1.2 The Future-Present Worth Relation

The future-present worth relation is used when it is desired to know the present sum of money of a future sum of money.

Objective: Find P when F is given.

Standard notation: $P = F(P/F, i, n)$

Equation:

$$P = F(1+i)^{-n} \quad 4.1$$

4.1.3 The Series-Present Worth Relation

The series-present worth relation is used when it is desired to know the present sum of money of a uniform series of end of period sum of money.

Objective: Find P when A is given.

Standard notation: $P = A(P/A, i, n)$

Equation:

$$P = A \left[\frac{(1+i)^n - 1}{i(1+i)^n} \right] \quad 4.2$$

4.1.4 The Arithmetic Gradient – Present Worth Relation

The arithmetic gradient-present worth relation is used when it is desired to know the present sum of money of a uniform series with and uniform increase end of period sum of money.

Objective: Find P when G is given.

Standard notation: $P = G(P/G, i, n)$

Equation:

$$P = G \left[\frac{(1+i)^n - in - 1}{i^2(1+i)^n} \right] \quad 4.3$$

4.1.5 The Geometric Gradient – Present Worth Relation

The geometric gradient-present worth relation is used when it is desired to know the present sum of money of a uniform series with and geometric increase end of period sum of money.

Objective: Find P when G_g is given.

Standard notation: $P = G_g(P/G_g, g, i, n)$

Equation:

$$P = G_g \left[\frac{1 - (1+g)^n (1+i)^{-n}}{i - g} \right] \quad 4.4$$

If $i = g$ then the Equation 4.4 becomes

$$P = G_g \left[n(1+i)^{-1} \right] \quad 4.5$$

4.2 The Rate of Return

The internal rate of return of a project is interest rate at which the PW of positive cash flows equals the PW of negative cash flows thus the NPW is equal to zero.

When economical alternatives are going to be analyzed it is important to evaluate them at a reasonable interest rate or discount rate better known as the minimum attractive rate of return (MARR), [Canada et al. 2004]. The MARR is the minimum rate of return that the investor is willing to obtain from an investment. This means that any rate of return method of economic comparison involves the calculation of a rate of return and comparison against a minimum standard of desirability known as the MARR. In general the MARR is a measure of profit potential and affects the decision of selecting projects for investment.

The selection of a MARR to evaluate a project is generally controversial and difficult. Some firms use criteria such as opportunity costs of capital, market interest rates and risks on investment to determine an acceptable value of MARR. Table 4.1, [Canada et al. 2004], shows categories of risk and the MARR that should be used for that risk.

Table 4.1: MARR Values for a Given Risk.

Category of Risk	Average MARR	Examples
High	40%	New products, new business, acquisitions, joint ventures
Medium	25%	Capacity increase to meet forecasted sales.
Low	15%	Cost improvements, Make versus buy, capacity increase to meet existing orders

4.3 Comparing Alternatives

The objective of a present worth economic analysis is to evaluate different alternatives for a specific project and select the alternative with the highest positive present worth, or the alternative with the smallest negative present worth in case that the available alternatives do not produce a positive economical yield.

To compare or evaluate alternatives a systematic procedure or analysis is used. Figure 2.1 shows a flowchart of the procedure. The procedure is as follows, [Canada et al. 2004]:

1. Define the alternatives. Select among a few alternatives or do nothing.
2. Determine the study period. This period can be the life of the project.
3. Provide estimates of the cash flows for each alternative. This is the most important part; poor estimates can give undesirable results and selection of an alternative that is not the best.
4. Specify the time value of money or interest rate. The time value of money can be minimum attractive rate of return (MARR) that the investor is willing to obtain from the project.
5. Select the measure(s) of effectiveness. In this thesis the measure of effectiveness is a positive value present worth.
6. Compare the alternatives. Which alternative has the highest present worth?
7. Perform sensitivity analysis. Which parameter variation can affect the outcome?
8. Select the preferred alternative.

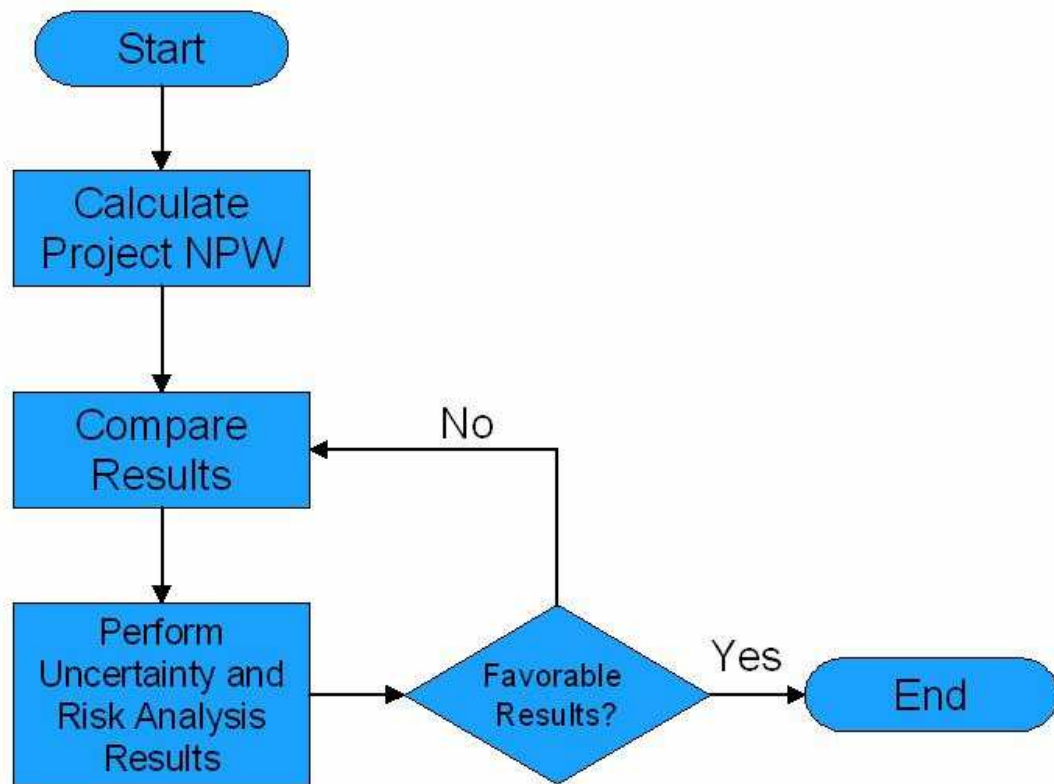


Figure 4.1: Flowchart for Comparing Alternatives.

4.4 Uncertainty and Risk Analysis

4.4.1 Introduction

Developing a wind farm project is a risky project. The fundamental risks encountered in the electricity supply industry are primarily market risks and technical risks. Market risks include demand growth, wind speed, the price of the land, cost of money, and tariffs. Technical risks include the breakdowns and non-availability of wind turbines, changes in technology, and prospects of future environmental legislation and

enforcement. During the implementation of the project there are also the risks of cost overrun and delays in implementation, [Khatib 1997].

4.4.2 Sensitivity Analysis

Following the procedure presented in section 4.3 after step number 6 a sensitivity analysis should be performed. The sensitivity analysis is an uncertainty analysis. The sensitivity analysis is performed when there is uncertainty on one or more parameters of the present worth analysis. The objective of the sensitivity analysis is to help in the decision making process by providing information on:

- How possible errors in the estimates of one or more parameters can affect the outcome of the economic effectiveness measure.
- Potential changes in the alternatives preferences.

In this thesis project the focus in sensitivity analysis are in:

1. Single parameter sensitivity graphs. These graphs show the effect of the deviation of individual parameters in the project outcome. The *ceteris paribus* assumption is used in which all the parameters are fixed to a base value and only the parameter under study is varied. This permit the study of a particular relationship (i.e. MARR vs. NPW) in a simplified setting.
2. Two parameters sensitivity graphs. These graphs show the effect of the deviation of two parameters in the project outcome, [Canada et al. 2004].

4.4.3 Monte Carlo Simulation

4.4.3.1 Introduction

The final step of the economical analysis is a financial risk analysis. For risk analysis the method used is known as Monte Carlo simulation, [Khatib 1997, Canada et al. 2004]. Monte Carlo permits to develop approximate solutions when a physical experiment or the use of analytical approaches is either too burdensome or not feasible and it is desired to analyze situations involving risk. In this thesis the purpose of performing Monte Carlo simulation is to evaluate the most sensitive parameters.

In Figure 4.2 we show the flowchart to perform a Monte Carlo simulation. To perform a Monte Carlo simulation we have to follow these steps:

1. Define problem and collect data. This data can be the selling price, the investment, the useful life of the project, salvage value, operating costs, etc.
2. The input data. This data includes the probability distributions of the collected data, time patterns, and initial investment conditions.
3. Decision rules and program. Randomly select sets of input data according to their probability of occurrence.
4. Simulate. Determine a measure of merit for each set of conditions.
5. Repeatedly sample until a clear pattern of investment risk is evident.

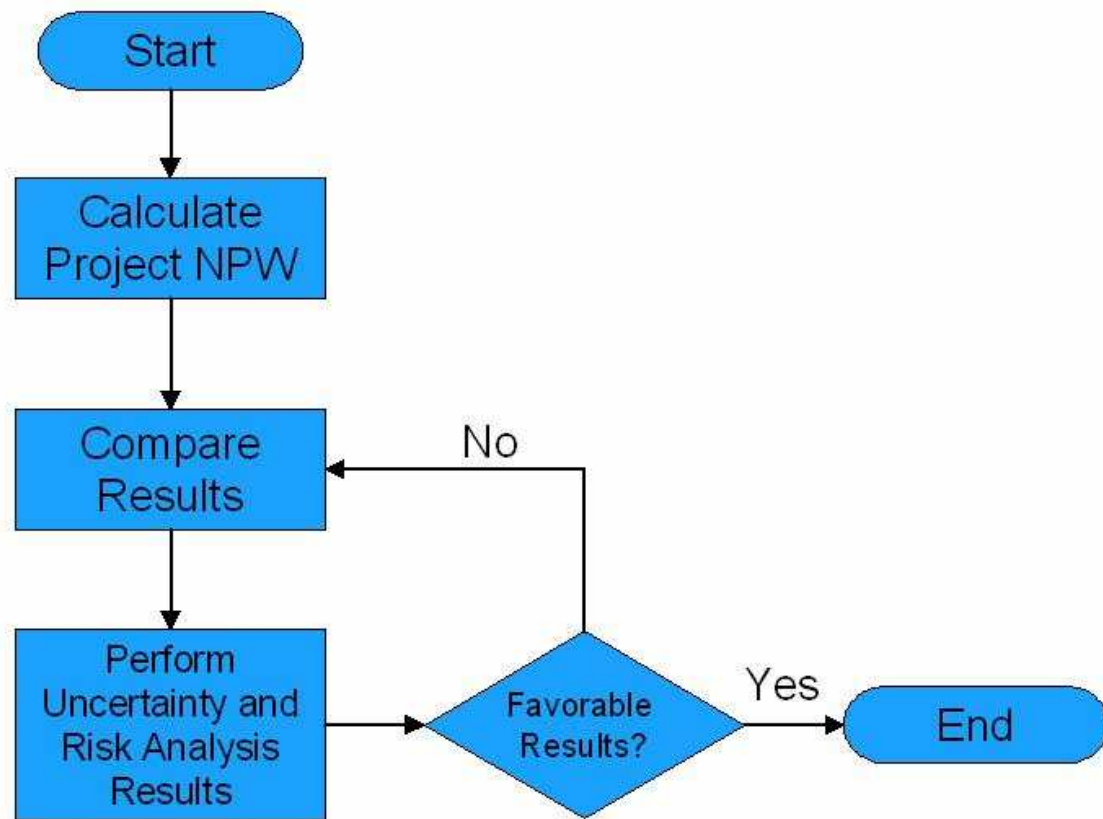


Figure 4.2: Monte Carlo Simulation Flowchart.

4.4.3.2 Modeling Parameters and Generating Random Numbers

The most important step to perform Monte Carlo simulation is to model the sensitive parameters under study with the most adequate probability distribution. The probability distributions can be triangular, normal, uniform or of any other empirical form. It is important to understand that using a not adequate distribution to model a parameter can result in misleading information about the financial risk of the project.

The next step before making the Monte Carlo simulation is to generate random numbers based on the probability characteristics given for the different parameters of the problem. The expression for the generation of random normal values is given in [Canada

et al. 2004]. The expression for generating random uniformly distributed values for the uniform, triangular, or any other empirical distribution can be obtained using the Inverse Transformation Technique, [Banks et al. 2004]. Table 4.2 shows generic expressions for generating random numbers for the normal, uniform and triangular distribution.

In Table 4.2 RND is a random normal deviate with mean zero, variance one and standard deviation one, and RN is a uniformly distributed random number between zero and one. The RND are used only with the normal distribution. RND and RN are obtained from specialized tables found in books such as [Banks et al. 2004] and also can be generated by software such as MS Excel and MATLAB.

Table 4.2: Random Number Generation Expressions.

Distribution	Expression
Normal	$mean + (RND)(std_deviation)$
Uniform	$a + (RN)(b - a) = \frac{mean}{2} - \frac{range}{2} + (RN)(range)$ <p>where a = Minimum and b = Maximum</p>
Triangular	$a + \sqrt{(b - a)(c - a)RN}, 0 < RN \leq (b - a)/(c - a)$ <p>where a = Minimum, b = Mode and c = Maximum</p>
	$c - \sqrt{(c - b)(c - a)(1 - RN)},$ $(b - a)/(c - a) < RN \leq 1.00$ <p>where a = Minimum, b = Mode and c = Maximum</p>

4.4.3.3 Measurements of Risk

The final step for completing the Monte Carlo simulation is to analyze the results. The most popular measurements of risk used are:

1. The Coefficient of Variation
2. The Probability of a negative outcome of NPW

The coefficient of variation is the standard deviation of the projected returns of Net Present Worth (NPW) divided by the expected mean value, [Hacura et al. 2001]. Assuming a positive expected mean value of NPW, the lower the coefficient of variation, the lower the project risk.

For the probability of a negative outcome of NPW generally, the project is quite safe when this probability is less than 0.2, [Hacura et al. 2001]. The critical value of this measure of risk is subjective since every manager has a different degree of aversion to risk.

4.5 The Economic Analysis Problem Formulation

4.5.1 Introduction

In this section the eolic generation economic analysis is formulated using basic concepts from microeconomic theory and engineering economics. Estimation of project profits, revenues and costs are discussed in detail.

As a general note when we refer in the following sections to the year n we mean the end of year n .

4.5.2 *The Economical Profits*

To develop an eolic generation project it is important to establish how the profits of the project will be obtained. From basic microeconomic theory it is established that the net profit (or loss) is given by the difference between the total revenues and the total expenses or as shown in Equation 4.6,

$$\pi(q) = TR(q) - TE(q) \quad 4.6$$

Where q is the quantity produced of certain good, $\pi(q)$ are the profits as a function of q , $TR(q)$ are the total revenues as a function of q , and $TE(q)$ are the total costs or expenses as a function of q . In this analysis the good, q , produced by a wind turbine is electrical energy that is for sale. Then, Equation 4.6 is interpreted as the net profit obtained from producing q energy and is the difference between the total revenues obtained from selling q energy and the total expenses from producing q energy. If the result from Equation 4.6 is negative we have a net loss instead of a net profit.

4.5.3 *The Revenues (TR)*

The revenue or gross profit is the income earned by a business as a result of providing products or services to customers. Revenue come from sales of merchandise to customers and from fees earned by services performed for clients or others.

The revenues for the eolic energy generation project will be given by the quantity of energy that is sold. Revenues are given by the product of the price of the available electric energy for sale and the established price of this energy as shown in Equation 4.7.

$$TR(q) = (energy_price) * (q) \quad 4.7$$

Where the energy_price is given in \$/kWh and q is the available electrical energy for sale in kWh and is given by

$$q = (energy_produced) * (avail_fac) * (1 - derating_fac) \quad 4.8$$

Where the energy_produced is the expected electric energy produced during a year assuming the wind turbines will work at ideal wind conditions (no turbulence) during 24 hours a day for a full year, the avail_fac is the percentage availability factor and is defined as the total time the wind turbines will be up producing energy, and the derating_fac is the percentage derating factor and is a derating of the wind turbine output due to turbulence and wind variations.

4.5.4 The Expenses (TE)

The expenses are the cost of doing business to generate the revenues of the specified operating period. Some common expenses are the cost of the goods sold (such as the manufacturing, production, shipping and distribution), the depreciation, the employees' salaries, the operating costs and income taxes.

The expenses or total costs are more complicated to calculate. Some of the expenses are fixed and does not depend of the electrical energy produced, q, others costs are

variable or controllable and depends on the q output. The following list shows examples of different controllable and fixed costs.

Controllable or Variable Costs:

Salaries, payroll, benefits, legal and accounting expenses, advertising and marketing expenses, auto and transportation services, office supplies, utilities, repair and maintenance, outside services.

Fixed Costs:

Depreciation (amortization of capital assets), loan payments, insurance, licenses and permits, other fixed monthly expenses.

The most common costs for the eolic generation project are the capital costs that include the turbine costs and wind farm installation, and the annual operating costs that include the annual debt payments, the wind farm operation and maintenance costs, and the land right (rent) costs.

4.5.4.1 The Capital Cost (CC)

The capital cost is better known as the project initial cost. Since this cost is estimated at the beginning of the project it has very low uncertainty and very good confidence. The capital cost of an eolic energy generation project may include:

- The price of buying the wind turbines, the power substation, and any other material needed to develop the project.

- The price of transportation of the wind turbines and other construction equipment.
- The installation cost of the wind farm that includes wind turbines, the power substation, construction of access roads, and any other equipment.
- Other initial costs that may include the training of the people that will install or maintain the wind farm during its operating life.

For this project an estimated cost of the cost per kW installed in the wind farm will be used. The cost per kW (\$/kW) is a linear relation made by previous wind farm developers based on their experience and the economical history of previous wind farm projects. Using this estimated cost the project Capital Costs (CC) can be estimated using Equation 4.9.

$$CC = (Inst_Cost) * (K) \quad 4.9$$

Where **Inst_Cost** is the cost in dollars per kW installed in the wind farm, and **K** is the installed capacity in the wind farm and its units are kW.

Investors use a mixture of debt and equity to finance a wind farm project. The percentage of the total initial investment provided by borrowed funds is known as the debt ratio. Financing a project with borrowed funds is known as debt financing. A typical debt ratio for a wind farm project is between 60% to 75%, this means that for the project the other 25% to 40% is financed through equity, in other words from the investor or company retained earnings, i.e. their own pocket.

There are two types of debt financing: term loans and bond financing.

- a) Term loans – These are short-term borrowing from financial institutions (banks).
 - Involve an equal repayment arrangement, where the sum of the interest and the principal payment is uniform.
 - Interest payments decrease while principal payments increase over the life of the loan.
 - Negotiation between borrowing entity and the financial institution is directly.
- b) Bond financing – Sale of long-term bonds; money is borrowed from investors for a fixed period.
 - Only interest is paid at the end of each year.
 - The principal is paid in a lump sum when the bond matures.
 - Flotation costs are incurred when issuing bonds.

Flotation costs are expenses the company incurs related with the issue of a bond, such as bankers' fees, lawyer's fees, accountant's costs and printing and engraving of the bonds.

There are two types of equity financing: use of retained earning and issuance of stock.

- a) Use of retained earnings – Use funds invested by the current or new owners of a company.
 - Some companies have cash in hand to make capital investments.
- b) Issuance of stock – Selling common stock to raise the required funds.

- The company goes public to raise the required funds.
- Flotation costs are incurred when issuing stock.

The initial cost (investment) for the investor at year zero (IC_0) is given by the difference between the capital costs and the borrowed funds (BF) and is given by

$$IC_0 = CC - BF \quad 4.10$$

The result from Equation 4.10 can be also known as the equity. The borrowed funds are the quantity of money that is borrowed from the bank or lender to finance the project. The payment of the loan becomes an annual operating cost.

From the previous discussion we know that the borrowed funds will fluctuate from 60% to 75% of the project capital cost. The lending institution will expect that the investor have contributed from his own assets and to have undertaken personal financial risk to establish the business before asking them to commit any funding. In this case the investor may need to invest at least 25% of the capital costs.

In this thesis we evaluate the wind farm project using debt financing: term loans and bond financing.

4.5.4.2 The Annual Operating Costs (A)

The annual operating costs are the costs endured to maintain the wind farm operating year by year for the whole life of the wind farm. Some of these costs are fixed, this mean that they do not change with the volume of energy production, others are variable and

depend of the volume of energy production (i.e. more production, higher the costs). The annual operating costs of an eolic energy generation project may include:

- The project annual debt payment. This is the quantity paid for the borrowed funds. In the case of financing through loans this payment will be constant for the life of the loan. If the project was financed selling bonds then the payment will become constant interest payments through the life of the bond and a principal lump sum at the bond maturity date.
- The operation and maintenance (O&M) costs. The O&M costs may include the maintenance personal (engineers, mechanics), electric power and water, replacement parts and project insurance.
- The Land Costs. This is what is paid for the land where the wind farm is sited. The land can be bought or rented.

Other costs may include depreciation and income taxes.

The following equations define the annual operating costs used to calculate the total annual operating costs in this eolic energy generation project.

The project annual debt payment general expression is given by,

$$ADP_n = (principal)_n + (Interest)_n \quad 4.11$$

Where principal is the fee paid, at year n, in dollars that contributes to reduce the debt, Interest is the fee paid, at year n, in dollars for using the borrowed money. If the project is financed trough loan terms then annual debt payment is given by,

$$ADP = BF(A / P, i, N) \quad 4.12$$

Where BF are the borrowed funds, (A/P, i, n) is the relationship that is obtained from equating Equation 4.2 to the ratio of A/P, i is the interest rate, and N is the loan life in years. An important note is that the ADP for term loans will always be constant from year 1 to year n, after that is zero.

If the project is financed selling bonds is important to notice that if the bond matures at year n then when applying Equation 4.11 to calculate the annual debt payment, the ADP will be constant from year j = 1 to year j = n - 1 and it will be equal to a constant interest payment except at year j = n where the ADP is equal to the interest payment plus the bond principal.

The total operation and maintenance (O&M) costs are defined by equation 4.13.

$$OM = (OMf) + (OMv) * (q) \quad 4.13$$

Where OMf are the fixed O&M costs in dollars, OMv are the variable O&M costs in dollars per kWh produced and q is the energy produced in kWh.

The total land costs are defined by,

$$Land = (P_L) * (gross_rev) + (turb_rent) * (T) \quad 4.14$$

Where P_L is a percentage value, gross_rev is the project gross profit or revenue in dollars given by Equation 4.7, turb_rent is a fixed quantity in dollars paid yearly for every turbine installed, and T is the total number of wind turbines installed.

After defining the equations that defines the project costs then the project total annual costs (TE_A) can be calculated using Equation 4.15.

$$TE_A = IC_0(A/P, i, N) + ADP + OM + Land \quad 4.15$$

Where (A/P , i , N) is the relationship that is obtained from equating Equation 4.2 to the ratio of A/P , i is the minimum attractive rate of return, and N is the project life. It is important to note that the initial cost (IC_0) is converted to an annual constant payment to be able to compute the annual total costs (TE_A).

To calculate the project total costs at present time (TE_0) then Equation 4.16 or 4.17 are used.

$$TE_0 = IC_0 + (ADP + OM + Land)(P/A, i, N) \quad 4.16$$

$$TE_0 = TC_A(P/A, i, N) \quad 4.17$$

Where (P/A , i , N) is the relationship that is obtained from equating Equation 4.2 to the ratio of P/A , and i is the minimum attractive rate of return, and N is the project life. It is important to note that the annual costs are converted to a present value to be able to compute the total costs at present time (TE_0).

4.5.5 The Cash Flow (CF) and the Net Present Worth (NPW)

An engineering economics financial analysis lives or dies by the cash flow. The cash flow statement shows the net result of the sum of the money that goes in and goes out during a period. Table 4.3 shows an example of a typical cash flow. In a cash flow the

money we receive (income) is assigned a positive value, the money that goes out (expenses) is assigned a negative value.

Table 4.3: Example of a Cash Flow Statement.

Year	0	1	2	3
Gross Revenue	0	\$60K	\$60K	\$60K
Capital Cost	-\$100K	0	0	0
Borrowed Funds	\$75K	0	0	0
Land Costs	0	-\$5K	-\$5K	-\$5K
O&M Costs	0	-\$10K	-\$10K	-\$10K
Ann. Debt Payment	0	-\$30K	-\$30K	-\$30K
Net Cash Flow	-\$25K	\$15K	\$15K	\$15K

From the previous example it is observed that a typical cash flow is negative at year zero, because is the moment when the investment is made. In the following years the expectation is to receive a positive cash flow for the life of the project, but this is not always the case. It can occur that the revenue in certain year is not as expected and as a result a negative cash flow is obtained. Also not always the cash flow is constant; there can be fluctuations in costs due to inflation, and predicted changes, such as wear and tear of equipment, that affect the revenues thus resulting in changes in the cash flow. Another factor that affects the cash flow are the income taxes that will be discussed in the following sections.

The before taxes cash flow (BTCF) for this wind farm project can be calculated using the following equations:

$$BTCF_n = -IC_0, \quad \text{where } n = 0$$

$$BTCF_n = TR_n - ADP_n - OM_n - Land_n, \quad \text{where } n > 0 \quad 4.18$$

Where IC_0 is the initial cost for the investor at year zero as given by Equation 4.10, TR_n is the total gross revenue at year n as given by Equation 4.7, ADP_n is the annual debt payment at year n as given by Equations 4.11 and 4.12, OM_n is the annual maintenance and operation cost at year n as given by Equation 4.13, and $Land_n$ is the annual land cost at year n as given by Equation 4.14. Note that the negative quantities mean costs or expenses.

Now that the wind farm BTCF is defined the before taxes project expected net present worth (NPW) can be calculated using the following equation:

$$NPW = -IC_0 + (TR - ADP - OM - Land)(P / A, i, N) \quad 4.19$$

Where $(P/A, i, N)$ is the relationship that is obtained from equating Equation 4.2 to the ratio of P/A , and i is the minimum attractive rate of return, and N is the project life. This equation is valid if the variables TR , ADP , OM and $Land$ remain constant for the complete life of the project, but unfortunately in this project that is not the case. Then to correct for this problem we use the following equation:

$$NPW = -IC_0 + \sum_{n=1}^N [(TR_n - ADP_n - OM_n - Land_n)(P / F, i, n)] \quad 4.20$$

Where $(P/F, i, n)$ is the relationship that is obtained from equating Equation 4.1 to the ratio of P/F , i is the minimum attractive rate of return, n is the end of year n , and N is the project life.

When we add the effect of the income taxes to our cash flow statement it becomes an after taxes cash flow (ATCF). The taxes are considered like another cost in the cash flow. Equation 4.21 shows the after taxes net present worth for the wind farm project.

$$NPW = -IC_0 + \sum_{n=1}^N [(TR_n - ADP_n - OM_n - Land_n - IT_n)(P / F, i, n)] \quad 4.21$$

Where IT_n are the income taxes paid at year n . In one of the following sections we will discussed how to calculate the income taxes.

4.5.6 The Effect of Inflation

The inflation is a general raise in the level of the prices paid for goods and services. It has the effect of reducing the acquisitive power of the money. Since the life of a wind farm project is expected to be of more than 20 years there can be fluctuations in the price of the energy that is for sale and some of the annual operation costs such as the operation and maintenance costs. If it is desired to evaluate the effect of inflating or escalating the price of X cost variable at a year n then the following equation should be substituted for X ,

$$X_n = X(1 + f)^n, \quad \text{where} \quad 1 \leq n \leq N \quad 4.22$$

Where X is the base price (price at present time or year zero) of a good or service, f is the average inflation rate or escalation factor of that good X , X_n is the price of X at the end of year n , and N is the wind farm project life.

For example Table 4.4 shows the effect of inflation on the energy price if it is assumed a base price (price at time zero) of \$0.09/kWh and an inflation rate of 2%.

Table 4.4: Example of the Effect of Inflation.

Year	Effect of Inflation on Energy Price
0	\$0.0900/kWh
1	\$0.0918/kWh
2	\$0.0936/kWh
3	\$0.0955/kWh
25	\$0.1477/kWh

The inflation of a product is determined from the consumer price index of the product. The index is based on basket of goods that an average consumer buys. The base price of that basket was \$100 in 1967, thus a CPI of 100 in that year.

The inflation rate of a product varies from year to year, but for financial analysis to simplify the analysis the average inflation rate of that product is used. This means that certain product may have a 3% inflation from year 0 to year 1, a 2% inflation from year 1 to year 2, and a 4% inflation from year 2 to year 3. To obtain the average inflation we use Equation 4.23.

$$f = \left(\frac{X_n}{X_0} \right)^{\frac{1}{n}} - 1 \quad 4.23$$

Where f is the average inflation rate, X_0 is the price or CPI of good X at year zero (base price), and X_n is the price or CPI of good X at the end of year n . For example if we want to obtain the general inflation rate of a product between the years 1992 and 1996 then $n = 1996 - 1992 = 4$, X_0 is the price at year 1992, and X_4 the price at year 1996.

There are two types of inflation rates: the general inflation rate and the specific inflation rate. The general inflation rate is based on all the products of the market. The specific inflation rate is based on a specific product in that market, for example in the energy market we have different inflation rates for the fuels such as coal and natural gas, the distribution and transmission of power, the operation and management of power plants, etc. For example, the general inflation may be estimated in 3%, but for the case of a wind farm the specific inflation rate for the land costs may be 1%, and for the operation and maintenance the inflation rate may be 2%. Thus, for the purpose of this analysis is important to inflate each variable with its corresponding inflation rate. If a variable does not have an inflation rate then that variable is inflated with the general inflation rate.

4.5.6.1 The Economic Analysis Under the Effect of Inflation

There are two types of economic analysis under the effects of inflation: the actual dollars analysis and the constant dollars analysis.

The actual dollars analysis use the estimates of future cash flows and takes in account any anticipated changes due to the effects of inflation. The constant dollars analysis is a representation of constant purchasing power. This relation is better illustrated with an example, but first we have to define how they relate to each other using Equation 4.24 and Equation 4.25, [Park 1997].

$$A_n = C_n (1 + f_{avg})^n \quad 4.24$$

$$C_n = A_n (1 + f_{avg})^{-n} \quad 4.25$$

Where A_n are the actual dollars at the end of year n in the cash flow, C_n are the constant dollars at the end of year n in the cash flow, and f_{avg} is the average inflation rate.

For example, let assume that company invest \$100,000 in a breaker production line during a period where the general inflation rate is 5%. The company expects to recover a positive cash-flow of \$50,000 the next five years. Table 4.5 shows the cash-flow.

Table 4.5: Cash Flow in Actual and Constant Dollars.

Year	Cash Flow in Actual	Conversion Factor	Cash Flow in Constant
0	-\$100,000	$(1+0.05)^0$	-\$100,000
1	+\$50,000	$(1+0.05)^1$	+\$47,619
2	+\$50,000	$(1+0.05)^2$	+\$45,351
3	+\$50,000	$(1+0.05)^3$	+\$43,192
4	+\$50,000	$(1+0.05)^4$	+\$41,135
5	+\$50,000	$(1+0.05)^5$	+\$39,176

Typical economical analysis without inflation is performed in actual dollars. This means that the actual dollars analysis is a prediction of net cash flow that the investor will have in a future year, for example the investor expects to receive \$50,000 at the end of year 5. The information the constant dollars give is due to the effect of inflation what purchasing power the investor will have at the end of year 5 with the \$50,000 he receives. The results show that the \$50,000 the investor receives at the end of year 5 are worth \$39,176 in today (year zero) money. In other words if the investor at the end of year 5 expects to buy a BMW that costs today \$50,000 he will not be able to do it and he will be able only to afford the BMW that costs today \$39,176.

The interest rates and the MARR are affected by the inflation. When calculations using actual dollars are made the interest rate used is known as the market adjusted interest rate. It is important to notice that the interest rate given by the lending

institutions is a market interest rate. When the calculations are made using constant dollars then the interest rate is known as the real interest rate. When there is no inflation both interest rates are the same. Equations 4.26 and 4.27 show the relation between both interest rates.

$$i = i_R + f_{avg} + i_R f_{avg} \quad 4.26$$

$$i_R = \frac{i - f_{avg}}{1 + f_{avg}} \quad 4.27$$

Where i is the market interest rate, i_R is the real interest rate, and f_{avg} is the general inflation rate.

In general, if we have a cash flow in actual dollars then to obtain the net present worth (NPW) we use the market interest rate (i), but if we have a cash flow in constant dollars we use the real interest rate (i_R).

Some important remarks about inflation analysis:

- Depreciation expenses do not increase with inflation, they remain as initially calculated.
- If a depreciable asset is sold, the selling price increases with general inflation.
- The repayment size of a loan do not change with inflation since is based on an historical contract amount.
- The inflation tends to decrease the rate of return of a project, thus reducing its net present worth (NPW).

4.5.7 *The Income Taxes*

There are various types of taxes. In this type of project the taxes to be considered are the property taxes and the income taxes.

The property taxes are based on the valuation of property owned, such as land, equipment, buildings, inventory, and the established tax-rates. They do not vary with income and are usually much lower in amount than income taxes, [Canada et al. 2004].

The income taxes are taxes on pretax income of an organization in the course of regular business. Income taxes are also levied on gains on the disposal of capital property. They are usually the most significant type of tax to consider in economic analyses, [Canada et al. 2004, Park 1997].

The calculation of the income taxes is based on accounting rules. In accounting the rules for distinguishing what is a revenue or expense and what is not is different than in finance. In finance positive cash flows are revenues and negative cash flows are expenses. Accountants consider the depreciation of capital as an expense, but the principal paid on the debt is not considered an expense. In finance we don't consider the depreciation as an expense because is not a cash outlay, but the principal paid in the debt is considered an expense (cost) because affects the cash flow annually.

Before calculating the income taxes of the wind farm project we have to follow the accounting rules to determine the project taxable income (TI). The taxable income has to be calculated for every year in the project life using Equation 4.28.

$$TI_n = TR_n - Land_n - OM_n - Dep_n - Interest_n - Inc_n, \quad \text{where } n > 0 \quad 4.28$$

Where TR is the annual gross revenue at year n calculated using Equation 4.7, $Land$ are the annual cost at year n incurred in the leasing of the land where the wind farm is sited, OM is the annual operation and maintenance cost at year n of the wind farm, Dep is the annual depreciation of the capital at year n , $Interest$ is interest paid for the borrowed money in year n , and Inc is any tax incentive or deduction given to the tax payer in that taxation period. In the next section we explain how to calculate the depreciation of an asset.

There is another way to calculate the taxable income parting from the before taxes cash flow of the project. Adjusting Equation 4.18 we have that the taxable income is:

$$TI_n = BTCF_n + ADP_n - Dep_n - Interest_n - Inc_n, \quad \text{where } n > 0 \quad 4.29$$

Where $BTCF_n$ is the before taxes cash flow at the end of year n , and ADP_n is the annual debt payment at the end of year n .

It is important to notice that the taxable income is not a constant. The gross revenue will vary with energy production year by year, the land and O&M may suffer inflation effects, the depreciation will depend of the schedule assigned to it as discussed in the next section, the interest paid on the debt decreases year by year, and the incentives can also vary year by year.

Once the taxable income is determined, the income taxes (IT) at the end of each year can be calculated using,

$$IT_n = (TI_n) * (tax_rate) \quad 4.30$$

Where TI_n is the taxable income at the end of year n , and tax_rate is the tax rate imposed by the government.

It is of importance to take into consideration that in the United States of America (USA) every state has its own taxation rules and the Federal government has its own. In the USA the state income tax rate are usually fewer than 10%, states such as Florida and Texas do not have income tax. The federal income tax rates are much higher than the state taxes and fluctuate from 15% to 35% in the case of corporations or businesses.

Most citizens and companies established in the island of Puerto Rico do not pay federal income taxes, but the state income tax rates in Puerto Rico are much higher than the state income tax rates in the USA States and compare with the federal income tax rate. Puerto Rico and the USA federal government use a similar tax rate known as the marginal tax rate. A marginal tax rate system divides the taxable incomes in brackets and depending of the taxable income of an individual, that individual is charged a tax. The logic behind the marginal tax rate is the higher your taxable income, the higher your tax rate will be. Table 4.6 shows a federal marginal tax rate structure for corporations, [Canada et al. 2004, Park 1997].

Table 4.6: Corporate Tax Structure.

Taxable Income (TI)	Tax Rate	Tax Formula
\$0 - \$50,000	15%	$0.15*(TI)$
\$50,001 - \$75,000	25%	$\$7,500 + 0.25*(TI - \$50,000)$
\$75,001 - \$100,000	34%	$\$13,750 + 0.34*(TI - \$75,000)$
\$100,001 - \$335,000	39%	$\$22,250 + 0.39*(TI - \$100,000)$
\$335,001 - \$10,000,000	34%	$\$113,900 + 0.34*(TI - \$335,000)$
\$10,000,001 - \$15,000,000	35%	$\$3,400,000 + 0.35*(TI - \$10,000,000)$
\$15,000,001 - \$18,333,333	38%	$\$5,150,000 + 0.38*(TI - \$15,000,000)$
\$18,333,334 and higher	35%	$\$6,416,666 + 0.25*(TI - \$18,333,333)$

For the analysis of investment decisions is very common to assume a constant tax rate equal to the marginal tax rate of the bracket that applies to a project. In the case where there state and federal taxes, both taxes are computed using the same methodology and the state taxes can be deducted from the taxable income to compute the federal taxes then the following equation applies to calculate an effective tax rate, [Canada et al. 2004]:

$$t_{eff} = fed_rate + st_rate - (fed_rate) * (st_rate) \quad 4.31$$

Where fed_rate is the federal tax rate, and st_rate is the state tax rate.

4.5.8 Depreciation

The purpose of depreciation is to provide for the recovery of capital invested in property or capital that is expected to decline in value as a result of time and use. The depreciation is the decrease in value of physical property with the passage of time. The depreciation has to be considered when making after-tax engineering economics studies.

For property to be depreciable it should meet the following requirements:

- It must be used in business or held for the production of income.
- It must have determinable life, and the life must be longer than one year.
- It must be something that wears out, decays, gets used up, becomes obsolete, or loses value from natural causes.

The depreciation of an asset is executed in what is called depreciation schedules. In the following sections we explain two of this depreciation schedules or methods.

4.5.8.1 The Straight-Line Depreciation Method

The straight-line method assumes that a constant amount is depreciated each year over the life of the asset. The annual depreciation deduction (ADD) is given by Equation 4.32.

$$ADD = (B - SV_N) / N \quad 4.32$$

Where B is the cost basis of the asset, SV_N is the estimated salvage (book) value of the asset at year N, and N is the project life. The cost basis (B) of an asset is normally the purchase price plus the cost of making the asset serviceable, thus including shipping and handling, insurance, installation, and training expenses. In this project, cost basis is synonymous to the project capital costs.

For this wind farm project, the salvage value of the turbines is assumed to be zero. The reason for this is that the objective of depreciating the asset is to reduce the taxable income, so a salvage value of zero increases the annual depreciation deduction. Also after a project life of 25 to 30 years is very probable that the components that compose the wind farm may have no value in the market. And finally, any salvage value given to an asset becomes a capital gain and is taxable.

If we use the straight-line depreciation method then the variable Dep from equations 4.28 and 4.29 becomes equal to the ADD, and will be constant for whole life of the project.

4.5.8.2 The Accelerated Depreciation Method

There are various accelerated depreciation methods. In this project we will use the Modified Accelerated Cost Recovery System (MACRS). The MACRS method establishes prescribed depreciation rates, called recovery allowance percentages, for all assets within a specified class. This eolic energy generation project is analogous to an electric power plant, thus we will use the recovery period of an electric power plant that is 20 years based on the MACRS property classifications. Table 4.7, [Canada et al 2004], shows the MACRS depreciation schedule with its recovery allowance percentages for an electric power plant.

For eolic generation the United States government has allowed a special depreciation schedule for wind turbines. The schedule is based on a 5 year MACRS. Table 4.8, [Canada et al. 2004], shows the 5 year MACRS depreciation schedule for wind turbines.

Table 4.7: MACRS Depreciation Schedules for an Electric Utility.

Year	Recovery Allowance Percentage
1	3.750
2	7.219
3	6.677
4	6.177
5	5.713
6	5.285
7	4.888
8	4.522
9	4.4622
10	4.4621
11	4.4622
12	4.4621
13	4.4622
14	4.4621
15	4.4622
16	4.4621
17	4.4622
18	4.4621
19	4.4622
20	4.4621
21	2.231

Table 4.8: MACRS 5 Year Depreciation Schedule.

Year	Recovery Allowance Percentage
1	20.00
2	32.00
3	19.20
4	11.52
5	11.52
6	5.76

As an example of using the MACRS lets assume a wind farm with a capital cost of \$100M and that will be depreciated with a MACRS 5 year schedule. Table 4.9 shows the depreciation schedule fro this type of project.

Table 4.9: Example of a MACRS Depreciation Schedule.

Year	0	1	2	3	4	5	6
Capital Cost	\$100M	\$100M	\$100M	\$100M	\$100M	\$100M	\$100M
MACRS	0	20%	32%	19.20%	11.52%	11.52%	5.76%
Depreciation	\$0	\$20M	\$32M	\$19.20M	\$11.52M	\$11.52M	\$5.76M

4.5.9 Uncertainty Analysis Using Sensitivity Analysis

The objective of the sensitivity analysis is to determine which parameters affect the project net present worth when small or large variations are made to the value of those parameters. The sensitivity analysis shows for which parameters is important to have good estimates because small variations can change the outcome of the project from attractive to non-attractive and vice versa. This analysis is a simple way of evaluating the vulnerability of the profitability of the project to likely future deviations in the parameters best estimates.

In the electrical power industry the price of the electrical energy is the most important item affecting a project's financial performance.

In this thesis we are analyzing single parameter sensitivity analysis and two parameter sensitivity analysis.

4.5.9.1 Single Parameter Sensitivity Analysis

The single parameter sensitivity analysis consists of graphs that show the effect of the deviation of individual parameters in the project outcome. All the parameters are fixed to a base value. These base values are obtained from the base cases that are under analysis. Then the parameter that is going to be studied is varied in a range that can vary from

minus 75% to plus 75% of its base value. This condition in which only one parameter is varied and the others are fixed to their base value is known as a *ceteris paribus* condition.

In this thesis our objective is to see how the net present worth (NPW) of the wind farm project changes when one of the parameters changes its value, and be able to identify the most sensitive parameters. To perform the sensitivity analysis we have to follow these steps:

1. Determine the project net present worth equation.
2. Establish a base case in which the estimates of all the parameters are acceptable.
3. Identify or select the parameter to study.
4. Select a variation range for the parameter; an acceptable range is from -75% to 75% of the parameter base value.
5. Vary the parameter between the established range using increments of 10% or 15% and determine the NPW for each variation.
6. Make a plot of the NPW versus the range (% deviation from estimated value).

The scaling or variation of a parameter, X , as described in steps 4 and 5 is made using the following equation:

$$X_v = X(1 + dev) \quad 4.33$$

Where X the base value of the parameter that's under sensitivity analysis, dev is a percentage value in decimal form that represents the variation of the parameter, and X_v is the result of that variation on the parameter X .

As an example, let's assume the land costs have a base value of \$50,000 annually and that it is desired to observe the effect of a change in that parameter in the project before

taxes NPW when all the other parameters are fixed to their base value. Lets take Equation 4.20, the before taxes NPW expression for this project, and adjust the land costs for sensitivity analysis. Then the expression for the sensitivity analysis becomes like Equation 4.34 where we have an independent variable, dev, and a dependent variable, NPW. The variable dev is varied in established range and the results for the NPW are tabulated and then plotted.

$$NPW = -IC_0 + \sum_{n=1}^N [(TR_n - ADP_n - OM_n - Land_n(1 + dev))(P/F, i, n)] \quad 4.34$$

Table 4.10: Results for the Sensitivity Analysis Example.

Base Value	\$50K	\$50K	\$50K	\$50K	\$50K	\$50K	\$50K
Deviation	-75%	-50%	-25%	0	+25%	+50%	+75%
Change	\$12.5K	\$25K	\$37.5K	0	\$62.5K	\$75K	\$87.5K
NPW	\$115K	\$110K	\$105K	\$100K	\$95K	\$90K	\$85K

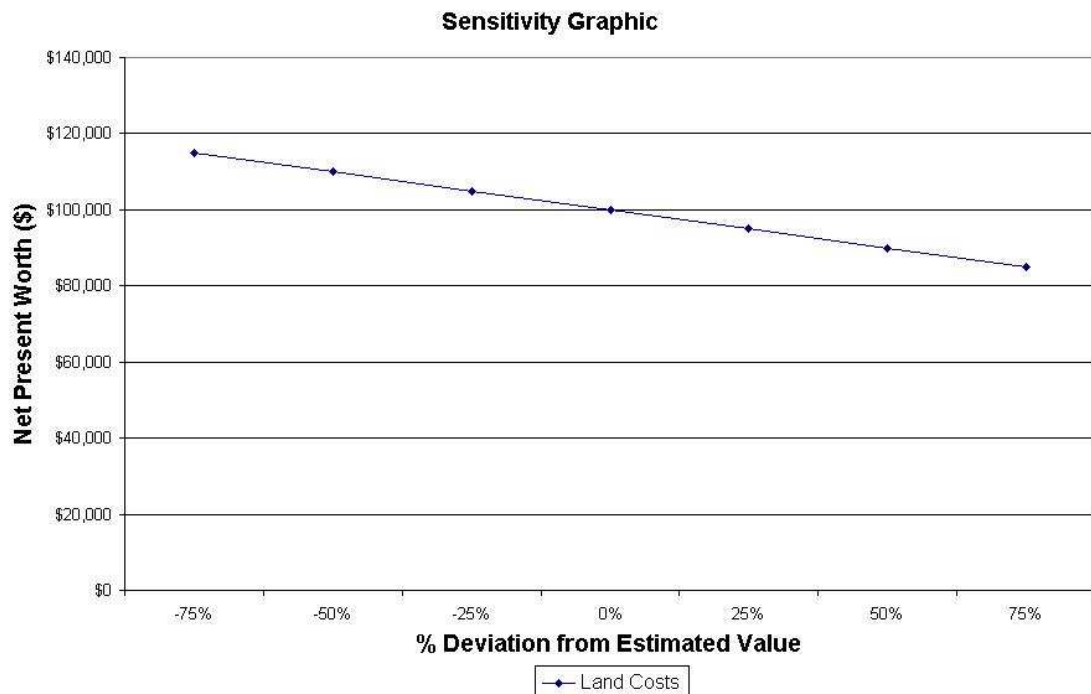


Figure 4.3: Example of a Sensitivity Graphic.

For this example it can be concluded that the land costs are not a sensitive parameter because the NPW does not change to negative a value when the land costs are varied in a wide enough range.

4.5.9.2 Two Parameter Sensitivity Analysis

The two parameter sensitivity analysis also is known as sensitivity surface analysis. It consists of a graphic that show the effect of the deviation of two parameters in the project outcome. All the other parameters are fixed to a base value. This base values are obtained from the base cases that are under analysis.

This analysis allows us to examine how the interaction of two parameters that can have estimation errors will affect the result of the project. For example, the case where the energy price decreases 10% and the operation and management costs of the project increases 5%. A two parameter sensitivity graphic would predict the outcome of the project for a situation like this.

As an example of a two parameter sensitivity analysis, we want to analyze how changes in the energy price and the annual debt payment affect the wind farm project outcome, in other words, to see if we get a positive or negative present worth. As a first step, we need an expression that describes the net present worth of the project. From previous sections, we have that Equation 4.20 describes the project net present worth. For simplification of the analysis Equation 4.20 can be rewritten as,

$$NPW = -IC_0 + TR_0 - ADP_0 - OM_0 - Land_0 \quad 4.35$$

Where IC_0 is the initial costs, TR_0 are the gross revenues at time zero, ADP_0 is the annual debt payment at time zero, OM_0 are the operation and management costs at time zero, and $Land_0$ are the land costs at time zero.

The projects energy price affects the variable TR in the net present worth expression. Equation 4.7 defines the variable TR. The variable TR_0 is defined as,

$$TR_0 = (energy_price) * (q)(P/A, i, N) = TR(P/A, i, N) \quad 4.36$$

Where q is the available electrical energy for sale in kWh, and $(P/A, i, N)$ is the relationship that is obtained from Equation 4.2 to the ratio of P/A , i is the minimum attractive rate of return, and N is the project life. This equation is valid if the parameter TR remains constant for the complete life of the project, but unfortunately in this project that is not the case. Then to correct for this problem we use the following equation:

$$TR_0 = \sum_{n=1}^N [(TR_n)(P/F, i, n)] \quad 4.37$$

Where $(P/F, i, n)$ is the relationship that is obtained from equating Equation 4.1 to the ratio of P/F , i is the minimum attractive rate of return, n is the end of year n , and N is the project life.

Equations 4.7 and 4.36 show the linear relation that exists between the gross revenues (TR) and the energy price. Now we can escalate the energy price as shown in the following equations.

$$TR_0(1+Y) = \sum_{n=1}^N [(energy_price_n)(1+Y)(q_n)(P/F, i, n)] \quad 4.38$$

$$TR_0(1+Y) = (1+Y) \sum_{n=1}^N [TR_n(P/F, i, n)] \quad 4.39$$

Where Y is a percentage value that represents the variation of the energy price.

The second parameter we want to study is the annual debt payment (ADP). The expression is developed using the same analysis described above modifying the expression of the annual debt payment and inserting to it an expression to escalates its values. The following expression is obtained,

$$ADP_0(1+X) = (1+X) \sum_{n=1}^N [ADP_n(P/F, i, n)] \quad 4.40$$

Where X is a percentage value that represents the variation of the energy price.

The next step is to substitute the expressions for the escalated parameters in the NPW equation and equate to be equal or higher than zero. The condition for the project to be profitable occurs when the NPW is equal or greater than zero for a given minimum attractive rate of return (MARR).

$$NPW = -IC_0 + TR_0(1+Y) - ADP_0(1+X) - OM_0 - Land_0 \geq 0 \quad 4.41$$

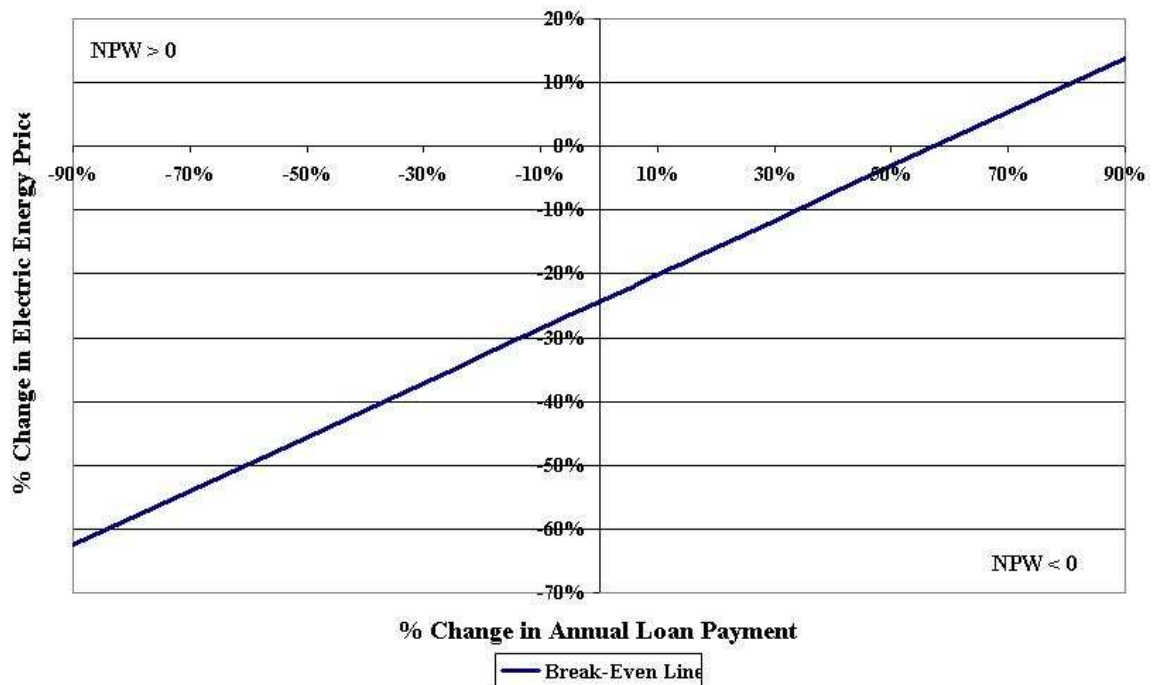
Now we take Equation 4.41 and equate it for Y as a function of X and obtain,

$$Y \geq \frac{IC_0 + ADP_0 + OM_0 + Land_0 - TR_0 + ADP_0 * X}{TR_0} \quad 4.42$$

The final step would be to make a plot of the above function. It can be appreciated that the function is linear. To make the plot we make a table as shown in Table 4.12 and evaluate the Equation 4.42 for a range of values of X. A typical range is from minus 90% to plus 90%. Equation 4.42 describes the energy price versus annual debt payment two-parameter sensitivity analysis.

Table 4.11: Results of a Sensitivity Surface (Two-Parameter) Analysis.

% Change in Annual Loan Payment (X)	% Change in Electric Energy Price (Y)
-90.00%	-62.56%
-70.00%	-54.07%
-50.00%	-45.58%
-30.00%	-37.09%
-10.00%	-28.60%
0.00%	-24.35%
10.00%	-20.11%
30.00%	-11.62%
50.00%	-3.13%
70.00%	5.36%
90.00%	13.85%

Two Parameter Sensitivity Analysis**Figure 4.4: Example of a Two-Parameter Sensitivity Graph.**

In two parameter sensitivity graphics we have to recognize three zones:

- The area over the curve. Every combination of changes in the two parameters that is over the curve will give a positive present worth or favorable outcome to the project.
- The area under the curve. Every combination of changes in the two parameters that is under the curve will give a negative present worth or not favorable outcome to the project.
- The Break-Even Line. Every combination of changes in the two parameters that is in the line will give a present worth equal to zero, this can be interpreted as a favorable outcome to the project.

For example a 70% increase in the annual debt payment combined with a 20% increase in the energy price will result in a positive present worth, but a 50% increase in the annual debt payment combined with a 10% decrease in the energy price will result in a negative present worth.

In this thesis we will use the two parameter sensitivity analysis and study four cases:

The energy prices versus the annual debt payment as described by Equation 4.42.

The energy prices versus the operation and maintenance costs as described by,

$$Y \geq \frac{IC_0 + ADP_0 + OM_0 + Land_0 - TR_0 + OM_0 * X}{TR_0} \quad 4.43$$

The energy prices versus the land costs as described by,

$$Y \geq \frac{IC_0 + ADP_0 + OM_0 + Land_0 - TR_0 + Land_0 * X}{TR_0} \quad 4.44$$

The operation and maintenance costs versus the annual debt payment as described by,

$$Y \geq \frac{-IC_0 - ADP_0 - OM_0 - Land_0 + TR_0 - ADP_0 * X}{OM_0} \quad 4.45$$

4.5.10 Risk Analysis Using Monte Carlo Simulation

In this thesis we use Monte Carlo analysis as a tool to measure the risk of the wind farm project. Typical construction of energy projects, such as building a power plant, may be assessed for uncertainty and risk using only sensitivity analysis, [Khatib 1997]. Developing a wind farm in the island of Puerto Rico is considered a risky project because it is “particularly a new venture with little past experience.”

The Monte Carlo simulation is a probabilistic method in which the net effect in the project net present worth is assessed due to changes in the economic parameters or the likelihood of various changes occurring together. The reason for this analysis is that in the real world there is no guarantee to ensure that the best estimate of the economical parameters will match the actual values, in other words, the cash flows are difficult to estimate accurately.

The objective of the simulation is to obtain a normal distribution that represents the outcome of the project: the projects net present worth or the internal rate of return, [Khatib 1996].

4.5.10.1 Setting Up the Monte Carlo (MC) Simulation

To set up a Monte Carlo simulation we have to model the most sensitive parameters as probability functions. In this thesis we will use the most common probability distributions used in Monte Carlo analysis. These distributions are:

- Normal distribution
- Uniform distribution
- Triangular distribution

The normal distribution will be used with any data that is known to follow a normal distribution, [Canada et al. 2004]. This is usually known from previous experience or collected data that shows that a parameter follows these distribution.

The uniform distribution is used when it is know that a parameter follows this distribution or when the only information known about a parameter is data that shows a range of value and it is known from that data that every value has the same probability of occurrence, [Park 1997].

The triangular distribution is used when it is known that a parameter follows this distribution or when the only information known about a parameter is data that shows a range of values and from this data a mode can be obtained. The mode is a value that is more likely to occur than are the other values, [Park 1997].

From this data using the expressions from Table 4.2 random numbers can be generated. The numbers generated are used as inputs in the economical analysis Monte Carlo simulation.

In this thesis we will assign the following probability distributions to model the parameters of our cash flow:

- The installed turbine cost (\$/kW) – Triangular distribution
- Energy price (\$/kWh) – Normal distribution
- Operation and Maintenance Cost (\$/kWh) – Uniform distribution
- Land Costs (\$/turbine) – Uniform distribution

Now substituting the corresponding expression from Table 4.2 in Equation 4.35 we obtain:

$$NPW_t = (-IC_{MC} + TR_{MC} - ADP_{MC} - OM_{MC} - Land_{MC})_t \quad 4.46$$

Each parameter of the above equation is defined as follows:

Project Initial Cost

$$IC_{MC} = (a_{CC} + \sqrt{(b_{CC} - a_{CC})(c_{CC} - a_{CC})RN}) * K - BF ,$$

$$\text{when } 0 < RN \leq (b_{CC} - a_{CC}) / (c_{CC} - a_{CC}) \text{ or}$$

$$IC_{MC} = (c_{CC} - \sqrt{(c_{CC} - b_{CC})(c_{CC} - a_{CC})(1 - RN)}) * K - BF ,$$

$$\text{when } (b_{CC} - a_{CC}) / (c_{CC} - a_{CC}) < RN \leq 1.00 \quad 4.47$$

Where a_{cc} is the minimum value of the installation costs (\$/kW), b_{cc} is the mode of the installation costs, c_{cc} is the maximum value of the installation costs, RN is a uniformly distributed random number as discussed in section 4.4.3.2, K is the wind farm installed capacity in kW, and BF are the borrowed funds.

Project Gross Revenues

$$TR_{MC} = \sum_{n=1}^N [(\mu_{EP} + (RND) * \sigma_{EP}) * q * (P / F, i, n)] \quad 4.48$$

Where μ_{EP} is the mean value of the energy price (\$/kWh), σ_{EP} is standard deviation of the energy price, RND is a random number deviate as discussed in section 4.4.3.2, q is the energy produced in a year (kWh), (P/F, i, n) is the relationship that is obtained from equating Equation 4.1 to the ratio of P/F, i is the minimum attractive rate of return, n is the end of year n, and N is the project life.

Project Operation and Maintenance Cost

$$OM_{MC} = \sum_{n=1}^N [(OM_f + (a_{OM} + (RN) * (b_{OM} - a_{OM})) * q) * (P / F, i, n)] \quad 4.49$$

Where a_{OM} is the maximum value of the variable O&M cost (\$/kWh), b_{OM} is the minimum value of the O&M costs, RN is a uniformly distributed random number, q is the energy produced in a year (kWh), and OM_f is the fixed O&M cost which in this thesis we presume to be zero.

Project Land Costs

$$Land_{MC} = \sum_{n=1}^N [(P_L * gross_rev + (a_{LR} + (RN) * (b_{LR} - a_{LR})) * T) * (P / F, i, n)] \quad 4.50$$

Where a_{LR} is the maximum value of the land rent per turbine installed (\$/T), b_{LR} is the minimum value of the land rent, RN is a uniformly distributed random number, T is the total number of wind turbines installed, P_L is a percentage value, and gross_rev is the project gross profit or revenue in dollars given by Equation 4.7.

4.5.10.2 *The Monte Carlo Simulation and the Measurements of Risk*

After the Monte Carlo simulation problem has been defined, the next step is to perform the simulation. The best method to keep track of the Monte Carlo simulation is by tabulating each trial. As an example let's observe Table 4.13.

Table 4.12: Example of a Monte Carlo Simulation.

Trials	RN_{CC}	RN_{OM}	RN_{LR}	RND_{EP}	NPW	Cumulative NPW	Avg. NPW / Trial
1	0.3820	0.2144	0.7145	-1.0326	\$1.95M	\$1.95M	\$1.95M
2	0.1007	0.4136	0.4992	-0.0767	-\$850K	\$1.11M	\$557K
3	0.5965	0.3837	0.9645	2.2400	\$4.08M	\$5.20M	\$1.73M
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
999	0.7175	0.2705	0.6741	-0.0389	\$5.29M	\$3.18G	\$3.18M
1000	0.6309	0.5019	0.3800	-0.4180	\$4.43M	\$3.18G	\$3.18M

From observing Table 4.12 it can be appreciated that for every Monte Carlo simulation trial we obtain a different value of NPW. In some trials the results will be negative. A histogram of the NPW can be made in which information of the probability of different outcomes can be obtained, such as the probability of having negative outcomes, the probability of obtaining the predicted NPW, the probability of obtaining a higher NPW than predicted, or the probability of obtaining a lower NPW than predicted, [Hacura et al. 2001].

The Monte Carlo analysis gives us the following measurements of risk:

- The project's mean NPW, standard deviation and coefficient of variation that is the obtained dividing the standard deviation by the mean (expected) NPW.
- The most probable maximum and minimum value of the NPW.

- The negative NPW results and the percentage (probability) of negative NPW results.

Table 4.13: Example of a Monte Carlo Simulation Measurements of Risk.

Measurements of Risk	Results
Expected Value (Mean)	\$3,181,940
Standard Deviation	\$2,955,740
Coefficient of Variation	0.93
Maximum NPW	\$8,079,444
Minimum NPW	-\$1,812,790
Negative NPW Results	194
% of Negative NPW Results	19.4%

The interpretation of the measurements of risk varies with the willingness to take risk that every manager or investor has. The following list suggests how to interpret the measurements of risk:

- Usually the smaller the standard deviation the less risky is the project.
- If the coefficient of variation is less than one, the less risky is the project.
- If the probability of a negative outcome (percentage of negative NPW) is less than 20%, the less risky is the project, [Hacura et al. 2001].

One of the important aspects of the Monte Carlo simulation is the number of trials. Monte Carlo simulation experts consider that the minimum number of trials should be 3,000. Others suggest a method in which the average answer of interest for increasing number of trials is plotted, and observe at what number of trials those answers have become stable enough within an acceptable range of variation, [Canada et al. 2004]. Figure 4.5 shows an example of this plot. The figure shows that after 700 trials the simulation is stable enough to be within the accuracy required.

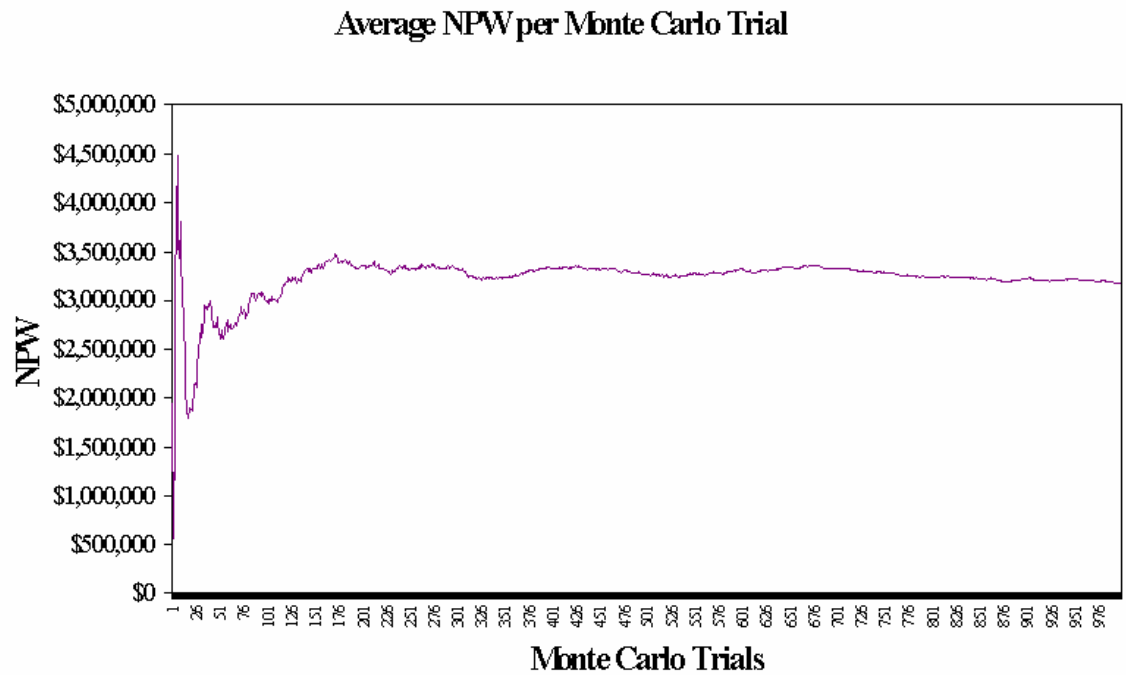


Figure 4.5: Example of a Monte Carlo Trials Plot.

The Monte Carlo method is limited by the probability distribution models and the parameter estimates used. This reminds us of the importance of being careful when modeling the economic analysis parameters.

4.6 Concluding Remarks

In this chapter we developed an economic model to analyze the feasibility of a wind farm project. The model is based on the net present worth method. Our model considers five main variables:

- The initial investment (cost). The cost incurred by the investor when starting the project. The initial cost is equity the investor use to finance the project.
- The annual gross revenue. The gross revenues are the result of selling the energy the wind farm produces.
- The annual debt payment. This is the operating expense that results from borrowing money from a financial institution.
- The annual operation and maintenance cost. The cost of giving proper operation and maintenance to the wind farm every year.
- The annual land rent cost. The quantity that is paid to the land owner for the rights of installing wind turbines in his property.

Also in this chapter we discussed the effect of inflation and income taxes to this economic analysis. Both tend to reduce the project net present worth. Finally uncertainty and risk analysis was discussed using Sensitivity analysis and Monte Carlo simulation.

5 WIND TURBINE SITTING

Establishing a wind farm requires some level of expertise in different areas of study that includes engineering, social sciences, land surveying, geology and ecology just to mention a few ones.

In this chapter, we divide the important aspects of establishing a wind farm in two categories: the technical or engineering constraints that have to be addressed in order to establish a wind farm, and the social and environmental effects that a wind farm may cause to the area where it is sited. When evaluating a site both aspects should be evaluated concurrently.

Also in this chapter we, discussed the spacing rules that have to be considered when designing a wind farm array.

5.1 Technical and Engineering Aspects

Technical aspects include having favorable wind conditions in the site, having a wide open area or suitable terrain with a strong enough soil to hold the wind turbines in that site, having access roads to that site, and having a suitable and near interconnection point to the electric power grid.

5.1.1 Wind Conditions

To develop a wind farm project is necessary to have knowledge of the wind behavior in the site or location where the turbines will be installed. Vegetation deformation in the

site provides a visual guide to assess if a site may be adequate for developing a wind farm. Other wind turbines already sited are another visual guide of the wind conditions in the site. Historic knowledge from residents of the area can help to identify sites with good wind resources. The topography of the terrain can also contribute to determine if the site has an adequate wind resource.

If a wind farm is intended to be developed in a location, then wind speed measurements for that location have to be taken. Measurements of the wind speed and direction shall be taken in the site for at least 12 to 24 months. The measurements should be taken at the hub height of a typical wind turbine (50 to 60 m), but if it is not possible to do that then measurements should be taken at heights of 10 meters and 20 meters. Measurements are taken at two different heights to be able to determine the wind shear factor at that site. Knowing the wind shear factor, wind speed measurements can be adjusted to any height at the site as discussed in Chapter 3.

The wind measurement equipment consists of an anemometer and a wind vane. The anemometer is installed at the top of a pole and connected to a data logger to record the wind measurements. Some poles permit to install more than one anemometer, one at the top of the pole and other at any other height in the middle of the pole. The wind vane measures the prevailing direction of the wind. The price of this measurement equipment is around \$5,000. More expensive towers that permit installation of three or more measurement units are available at considerable more cost.

Knowing the prevailing wind direction is very important. The wind turbines shall be installed facing the prevailing wind direction. Meteorological data in terms of a wind

rose⁵ calculated over a 30 year span is a very useful data to determine the prevailing wind direction in an area.

An important factor to consider in Puerto Rico are the tropical storms and hurricanes common in the period from June to November. Wind turbines have a rated wind speed known as the survival wind speed. At this wind speed, the rotor of the turbine can survive without receiving damage. The survival wind speed of a turbine varies with the model. A typical range is between 50 to 70 m/s, this equivalent to 113 to 159 mph. Figure 5.1 shows a map of the worst hurricanes that have hit Puerto Rico in the last century. Table 5.1 shows sustained wind data of each hurricane.

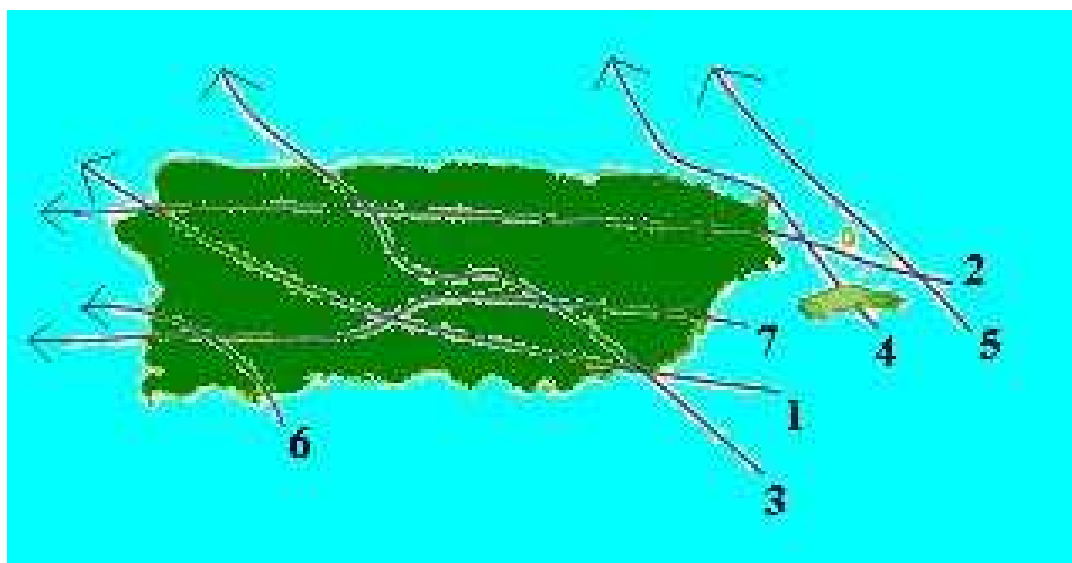


Figure 5.1: Hurricane Map for Puerto Rico (1900-1999).

⁵ A wind rose is a graphical representation of the wind speed and wind direction for a set of given dates at a particular location. The wind rose can be representative of the wind for a single month, a single year or a long term average by month or year. There are two graphics for each wind rose. One graphic depicts the average wind speed by wind direction in miles per hour. The other graphic represents the percentage of frequency by wind direction.

Table 5.1: Hurricane Data.

#	Hurricane Name	Year	Winds in mph	Category
1	San Felipe	1928	160	5
2	San Ciprián	1932	120	3
3	Santa Clara	1956	92	1
4	Hugo	1989	140	4
5	Marylin	1995	< 130	3
6	Hortense	1996	80	1
7	Georges	1998	115	3

Although hurricanes are common in the Caribbean and some major hurricanes had hit the Island, the probability of a hurricane hitting the Island every year is very low. According to statistical data compiled for a 100 year period by the National Hurricane Center, on average every 2 to 3 years a tropical storm with the potential to cause damages passes near the island. In the case of hurricanes it happens every 5 to 6 years on average, [Link 2003]. The east coast of Puerto Rico is the usual entrance point of hurricanes to the island. Since the most favorable places for wind farms are on the east coast, selecting a wind turbine with a survival wind speed of not less than 60 m/s (136 mph) is necessary.

5.1.2 Terrain

The terrain should have a wide an open view of the prevailing wind direction. There should be as few obstacles and as low terrain roughness⁶ as possible in the prevailing wind direction. Sites with rounded hills can cause a speed up effect on the wind. Also spaces between mountains can cause a tunnel effect, thus, creating a speed up effect, [DWIA 2003].

⁶ Terrain roughness is a measure of the undulation of the terrain surface.

Wide open areas with a good wind resource are the best for developing a wind farm because they reduce the energy losses due to turbulence and provide space making easier to maneuver heavy equipment needed to install the wind turbines. If the site is located near coastal area with a commercial dock, transportation costs of the wind turbine towers can be reduced and the energy losses to turbulence are minimized because the water is considered to have the lowest terrain roughness.

Installing turbines at the top of hills or between mountains (valleys) is also favorable for wind farm development. The hill and tunnel effects cause a speed up of the wind speed in those areas. The effect is similar to putting nozzle into a garden hose that causes the speed of the water to increase.

5.1.3 Grid Connection

Sites with at least a moderate (5 m/s) wind resource use large wind turbines that are usually connected to the electrical grid. The generator output voltage is between 400 V to 800 V. Each turbine in a wind farm has its own breaker panel inside of the base of the tower that connects them to a step-up pad mounted transformer located next or inside the tower. The transformer of each turbine is connected to a 4 feet deep underground cable that runs besides the wind farm roads and connects them with a power substation that converts electricity to transmission or distribution level voltages. The substation consists of a control house, transformer bank, protection system, support structure and lightning suppressors. The substation is installed on a concrete foundation designed for the soil conditions of the site.

Wind turbines can cause power quality problems to the electrical grid such as frequency and voltage stability problems, harmonic distortion and flicker. To prevent power quality problems, wind turbines are connected and disconnected gradually from the grid using electronically controlled switches such as thyristors. If the turbines were not controlled when the wind conditions were under their cut-in wind speed the turbines would act as a motor to the system. Otherwise when the wind speed increase above the cut-in the sudden switch from motor operation to generator would cause a brownout followed by a power surge. If the turbine is connected to a weak electrical grid (one with low power carrying ability and very far away of the system) brownout, power surge and flickering problems due to wind variations can occur, [DWIA 2003].

Wind farms can be used in distributed generation (DG) applications. One of the main problems of DG is islanding. Islanding occurs when the main power source stops supplying power to a region due to a fault in a line and the DG source continues to supply power to the isolated part of electrical grid causing an island or a separated grid. The problem is that when the main power source is reestablished, two separate out of phase grids become one again causing a sudden current surge that can damage the grid and wind turbines. To prevent islanding, the turbines electronic controller monitors the voltage and frequency in the grid, and automatically disconnects the turbines from the grid if the voltage and frequency variations in the grid are out the acceptable limits, [DWIA 2003].

5.1.4 Soil Characteristics

The soil where the wind turbines will be installed must be capable of holding the foundations needed for the turbines and the turbines itself. Table 5.2 shows typical weights for wind turbines.

Table 5.2: Wind Turbine Weight.

Turbine	Hub Height in meter	Weight in Tons			
		Rotor	Nacelle	Tower	Total
Gamesa G83 2 MW	60	45.9	61.2	120	227.1
	67	“	“	135	242.1
	78	“	“	190	297.1
	100			231	338.1
Vestas V52 850 kW	40	10	22	39	71
	44	“	“	44	76
	49	“	“	49	81
	55	“	“	57	89
	60	“	“	69	101
	65	“	“	77	109

The type of foundations needed vary with the soil conditions of a site. A wind farm site can have different soil conditions. Some types of soil require the installation of piles (pile driving) which complicates the installation of a turbine and increases the installation costs. The most common type of foundations for in-shore wind farms are the concrete slab type and the concrete cylinder type. The concrete slab foundations have a diameter of 30 to 50 feet and a support column. The buried cylinder foundations have a diameter of 15 feet. The depth at which both of these foundations are constructed depends on the type of soil and sub-soil.

5.1.5 Roads

A prospective wind farm site must have access roads. There has to be an access to the site so the developers will be able to visit and study the wind and soil conditions. Before the construction phase starts, the access roads shall be graveled and reinforced to allow heavy equipment to reach the site. The roads should be reinforced according to the weight of the wind turbine that will be installed in the site.

Another important aspect to consider is where the wind turbines are to be delivered. How far from the delivery point is the wind farm site? Are there access roads capable of withholding the weight of the turbines when they are transported to the site? Are there bridges along the way that can withhold the weight of the turbines? It is important to have a road map that shows the weight capacity of each road and bridge as well as turning radius.

5.2 Social and Environmental Aspects

Social and environmental aspects are incredibly important. Although wind power does not pollute the air or the water, it does not fly free of social and environmental concerns. The development of a wind farm can be halted for social and environmental issues such as the noise the turbines produce, the danger that the construction phase and particularly the turbines' blades represent to the wildlife especially migratory birds.

5.2.1 Visual Impact

The visual impact of a turbine is subjective. Some people may like how the turbine looks in the landscape, others would not, [Moragues and Rapallini]. Other people like the idea of wind farms, but they don't like the idea of having a wind farm in their community because they are concerned with the visual (aesthetical) and noise impacts. The "Not In My Back Yard" (NIMBY) syndrome is always a problem.

When a wind farm is installed near a community the color, the array of the turbines, and the rotor speed influence the visual impact that a turbine has. The wind turbines tower should be painted light grey because the wind turbines will blend well into the landscape, [DWIA 2003]. Also the use of large wind turbines is preferred because it means less wind turbines in a wind farm array. The low moving turbines are also preferred because they attract less the attention of the people.

The natural contours where the turbines are installed also contribute to the visual impact they have. When the turbines are sited in flat areas the turbines are arranged in an array forming a simple geometrical shape. Also turbines placed in a straight line work well where landscapes contour invites such a solution. If the contour is hilly the wind turbines are arranged following the altitude contours of the landscape, [DWIA 2003]. Arranging the turbines with the natural contour gives the visual impression of having a reduced amount of turbines, [Kingsley and Whittam].

Shadow casting is a visual effect that affects people who lives near a wind farm. Wind turbines cast shadow on the neighboring area. Rotor blades chop the sunlight

causing a flickering effect while the rotor is in motion. This flicker can be annoying to neighbors, [DWIA 2003].

5.2.2 Noise

Modern turbines produce little noise. The effects of the noise of a wind farm are very irrelevant. It is recommended for communities near wind turbines that turbines should be installed a minimum distance to the nearest neighbor of seven rotor diameters or 300m (1000 ft.). The noise level at 300m away from the turbine is less than 40 db, [DWIA 2003].

Other noise effect of a wind farm occurs during the construction phase of the farm. The use of heavy machinery and the pile driving will produce noise that can be annoying to the near neighbors, but such noise is most likely to occur during daytime hours only, [IEC].

5.2.3 Environmental and Wild Life Impact

The environmental effects of a wind farm can be divided as construction phase effects and project life effects. The most common construction phase effects are damage to the vegetation and turf, and the difficulty of reestablishing that vegetation when the construction phase is over, [IEC]. The project life effects are usually associated with the migratory birds and bats.

During the construction phase large quantities of the top soil and vegetation are removed for the construction of the access roads and the turbine foundations. This process put in danger plants and small animals that live in that area. The problem could

be worse if that is the habitat of endangered species. It is of importance that the turf and vegetation that is removed to be preserved and to be relayed after the construction phase is completed, [IEC].

In the case of offshore wind turbine installation the construction phase problems are more challenging. The construction of foundations can cause the destruction of the flora and fauna that lives in the bottom of the sea. The underwater excavations cause sediment spill and increase in the turbidity of the water. The turbidity of the water changes the composition of the flora and fauna in the area. The noise and vibration of the construction affects the communication and hunting habits of animals and force them to leave their habitat.

After the wind farm construction phase is over and the project life starts there is another environmental impact to consider: migratory birds. Birds are seldom bothered by wind turbines as supported by studies that shows mortality rate at wind sites between 1 to 2 birds per year per turbine, [FWS]. Some birds get accustomed to wind turbines very quickly; others take somewhat a longer time. Human related causes such as power lines, communication towers, cats, buildings, vehicles and pesticides are a much greater danger to birds. A house cat kills more birds in a year than a wind turbine, [Curry and Kerlinger 2000]. Out of every 10,000 birds killed annually in the U.S.A. by human related causes less than one is killed by wind farms, [FCN].

The bird mortality problem due to wind turbines is known as “avian issues”. The source of the avian issues came from a famous wind farm in the state of California, the Altamont Pass Wind Resource Area (APWRA) established in 1982. This wind farm is

one of the biggest in the world and contains 5,400 wind turbines and the capacity to generate 584 MW. The problem that APWRA has is that it has the highest mortality of birds. Estimates show that 1,766 to 4,721 birds are killed each year in the wind farm, of those birds 881 to 1,300 are protected raptors, [CBD 2004, FCN].

Studies have been made by the California Energy Commission and NREL to determine how it is possible to deduce the mortality of birds in the APWRA. The studies suggest the following recommendations:

- Replace outdated wind turbines with modern turbines. Modern turbines have higher output power and are taller, so fewer turbines will be needed and the blades are above most raptors flight patterns.
- Use of tubular towers to prevent the birds perching in them.
- Shutdown the turbines that are considered lethal during the parts of the year when the species migrate.
- Retrofitting power poles to eliminate the electrocution of birds in the adjacent power lines.
- Paint the blades of the turbines to increase the visibility of them.
- Install structures at the end of the turbines strings to divert birds around the turbines blades.
- Rodent prey management practices to control food source populations that congregate around the base of the turbines.

Environmentalists refer to Altamont Pass as a fiasco. Altamont Pass has hampered wind power development in the United States, especially in the state of California. Tom Gray, communication director of the American Wind Energy Association (AWEA) said: “Altamont Pass is not representative of wind farms across the United States.”, “Wind farms do coexist successfully with wild life in many other locations.”

On the other hand, the APWER wind farm has provided the state of California with the following environmental and economical benefits, [FCN]:

- Reduced air emission by the equivalent of 1.2 billion pound of CO₂, 183,000 pounds of NO_X, 161,000 pounds of particulate, and 12,000 pounds of SO_X.
- Avoided the annual consumption of conventional fuels equivalent to 3.7 billion cubic feet of natural gas, or 152,000 tons of coal, or enough nuclear fuel create 7,000 pounds of high level nuclear waste.
- Reduced water consumption by 282 million gallons per year.
- Generates enough electrical energy to serve the equivalent of 180,000 homes.
- Provided more than \$500 million in local economic benefits over the past 20 years.

Although the APWER project has a high bird mortality rate, it has provided other environmental benefits. Altamont Pass has been an isolated case and from it developers and wind energy advocates have learned of ways to reduce the bird mortality in other wind farms.

To avoid bird collisions with wind turbines the Canadian Wild Life Service, [CWS], and the AWEA suggest:

- Selecting sites with small population of birds.
- Avoid large-scale wind projects in areas of high bird usage or significance, and where endangered species live.
- Avoid natural areas and use human-altered landscapes.
- Space turbines more widely in areas of heavy bird migration.
- Painting the blades so they contrast with the background.
- Use a radio frequency broadcast to discourage birds from entering the wind farm area.
- Use of bird path maps to avoid sitting the turbines near populations of endangered species.

Studies realized in the Yukon area and in Canada concluded that migratory birds do not collide with wind turbines. A study using radar technology made in Tjaereborg, Denmark where a 2 MW wind turbine was installed showed that the birds modified their flight route 100m to 200m before the turbine and flied at a safe distance from it, [DME]. Also in a wind farm in Garret, Pennsylvania there have not been documented bird deaths since they started operation in the year 2000, [Kilkelley].

5.3 Designing a Wind Turbine Array

Wind turbine arrays are designed using a rule of thumb suggested by the Danish Wind Energy Association. The “Rule of Thumb” (ROT) for making an array of wind turbines is, [DWIA 2003]:

One row of wind turbines have to be 5 to 9 rotor diameter apart to the other row in the prevailing winds (parallel) direction. One row of wind turbines have to be 3 to 5 rotor diameter apart to the other row in the direction perpendicular to the prevailing winds.

The rule of thumb can be applied in open field areas to form arrays with a rectangular or square geometric shape. Figure 5.2 shows a visual example of the “Rule of Thumb”. The idea of the rotor spacing of this rule is with the objective of minimizing the shading one turbine causes the other, in other words the turbulence of the wind that enters a turbine. The first row of turbines will not encounter turbulence problems, but due to the wake effect, the row behind the first has to be spaced considerably to avoid turbulence and low energy winds. The wake occurs because when a turbine extracts energy from the wind, the wind exiting the turbine is slowed down and turbulent. Using the ROT the energy losses due to turbine shading and turbulence can be reduced to a 5%.

When designing wind farms in areas where the contour is part of the natural beauty of the site the turbines should be placed following the contour, but with the spacing suggested by the ROT.

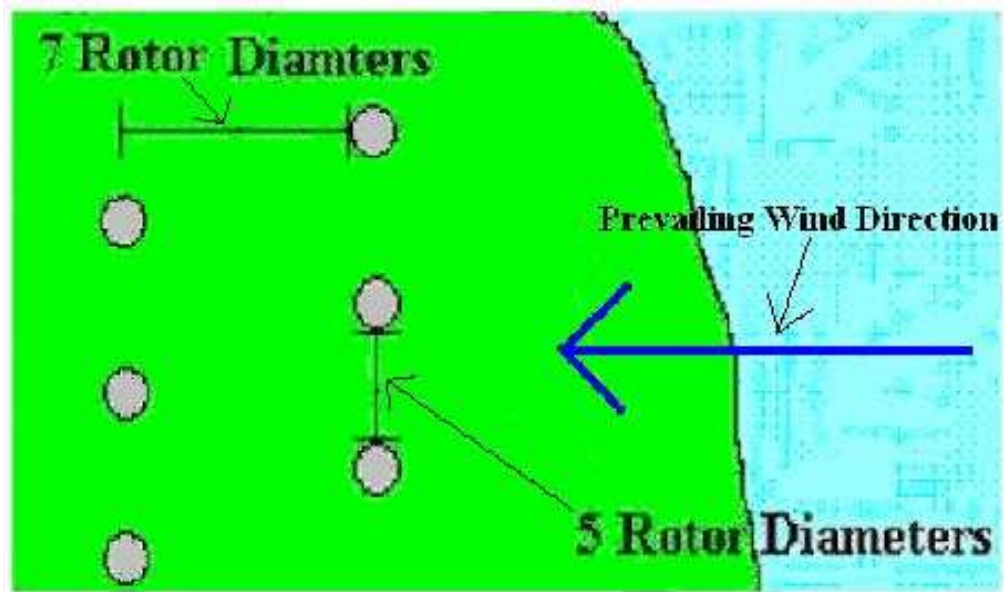


Figure 5.2: Visual Example of the “Rule of Thumb”.

5.4 Concluding Remarks

In this chapter we discussed engineering, social and environmental aspects of wind farm siting. The engineering aspects include the measurement of wind speed to determine wind conditions, the analysis of terrain and soil conditions adequate for the construction of roads and the installation of wind turbines, and considerations that have to be taken for the grid connection such as harmonic distortion, islanding, and voltage and frequency variations.

In the social and environmental aspects we discussed the noise and visual impacts that wind turbines cause to people, and the wild life impact especially to migratory birds. Wind farms kill fewer birds than other human related causes. We also mentioned suggestions to reduce bird mortality.

Finally the “Rule of Thumb” for spacing wind turbines in wind farm arrays was discussed. The “Rule of Thumb” helps reduce energy losses, by reducing turbulence, to less than 5%.

6 RESULTS AND DISCUSSION

In this chapter we present the results of the analysis made to determine the favorable conditions for the development of a wind power farm in Puerto Rico. This chapter is divided in two main sections in which the results for the data analysis and the economical analysis are shown.

The wind speed data analysis results show the Weibull parameter estimation, the average wind speeds and the expected energy production for each month and a year. Also energy production curves are presented for different turbine models using the year data.

The economic analysis sections are divided in two main study cases: the private investor case and the utility case. In the private investor case, we examine various scenarios given the proper economic parameters that a private investor will encounter if he/she decided to develop a wind farm. In the utility case, we assume the Puerto Rico Electric Power Authority (PREPA) is the developer.

6.1 Data Analysis Results

6.1.1 Quarterly and Full Year Data Analysis

In this section we divide the wind data analysis results in quarters. The first quarter includes the months of February and March. The second quarter includes the months of April and May. The third quarter includes the months of July and August, and the fourth quarter includes the months of November and December. Then the wind data measurements are added to form a set of data representative of a full year. The measurements were taken in the year 1987 in Fajardo, Puerto Rico at a height of 25 meters. The site of the measurements is located very near the coast in an area that is known as the Cape of San Juan. The results from the full year analysis are used as the base for energy production estimates for the economic analysis.

Data for the months of January, June, September and October is missing due to failures in the measurement equipment and lack of visual inspection during the measurement stage, [Soderstrom 1989].

The wind speed data is tabulated as hourly observations in [Soderstrom 1989]. Also in Appendix A, we show the results for the data analysis of every available month individually.

The first step in the data analysis was to estimate the Weibull pdf parameters. As stated in Chapter 3, the Weibull pdf has two parameters: the shape (β) factors and the scale (η) factor. In Table 6.1 we show the parameters obtained using the different parameter estimation methods previously discussed.

Table 6.1: Parameter Estimation Results.

<i>Parameter Estimation Results for the First Quarter for 1987</i>				
Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	3.01	3.62	2.33	3.07
Scale Factor (η, c)	6.82	6.85	7.15	6.85
<i>Parameter Estimation Results for the Second Quarter for 1987</i>				
Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	2.72	3.13	2.27	2.76
Scale Factor (η, c)	6.87	6.90	7.08	6.89
<i>Parameter Estimation Results for the Third Quarter for 1987</i>				
Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	3.16	3.72	2.69	3.14
Scale Factor (η, c)	7.14	7.53	7.30	7.17
<i>Parameter Estimation Results for the Fourth Quarter for 1987</i>				
Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	2.47	2.78	2.10	2.51
Scale Factor (η, c)	8.25	8.30	8.47	8.28
<i>Parameter Estimation Results for the Full Year for 1987</i>				
Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	2.68	3.60	2.33	2.74
Scale Factor (η, c)	7.29	7.22	7.49	7.31

After estimating the Weibull pdf parameters, we analyzed the Weibull pdf and calculated the site average wind speeds. Two average wind speeds were calculated: the arithmetic mean speed and the cubic root cube mean speed. This process was made using the parameters obtained from the different estimation methods. Table 6.2 includes the average wind speed obtained using the different parameter estimation methods previously discussed.

To calculate the available energy and wind power density in the site we used the Weibull pdf parameters estimated using the maximum likelihood (ML) function since this method gives more precise results for a large sample. First, we calculated the maximum energy that can be produced or extracted by a wind turbine in the site; this is not considering the Betz's limit and assuming a 100% of efficiency for a wind turbine. The energy density, in kWh/m^2 , is calculated using two different methods. The first method is integrating the energy probability function (EPF) from 0 to infinite; the second method is substituting the calculated arithmetic mean or cubic root cube mean wind speed in the wind power equation and multiplying it by the total hours in the analysis period. We also calculated the energy an ideal turbine (no Betz's limit, 100% efficiency) can capture if it operates between the typical range of 3 m/s to 25 m/s. This is done integrating the EPF from 3 m/s to 25 m/s.

In Tables 6.3 and 6.4 we present the energy and power density results obtained using the parameters estimated from the ML function and the methods described in the above paragraph.

Table 6.2: Average Wind Speed Results.

<i>Average Wind Speed Results for the First Quarter for 1987</i>				
Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.09	6.17	6.33	6.12
Cubic Root Cube Mean Speed	6.81	6.70	7.50	6.81
<i>Average Wind Speed Results for the Second Quarter for 1987</i>				
Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.09	6.18	6.27	6.13
Cubic Root Cube Mean Speed	6.95	6.86	7.48	6.96
<i>Average Wind Speed Results for the Third Quarter for 1987</i>				
Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.39	6.41	6.49	6.79
Cubic Root Cube Mean Speed	7.09	7.10	7.43	7.10
<i>Average Wind Speed Results for the Fourth Quarter of 1987</i>				
Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	7.27	7.39	7.51	7.35
Cubic Root Cube Mean Speed	8.47	8.38	9.17	8.52
<i>Average Wind Speed Results for the Full Year for 1987</i>				
Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.48	6.51	6.63	6.51
Cubic Root Cube Mean Speed	7.42	7.07	7.83	7.42

Table 6.3: Energy Production Results.

<i>Energy Production Results for the First Quarter of 1987</i>		
Energy Production Parameter		
Energy Probability Function (kWh/m²)	Arithmetic Mean Wind Speed (kWh/m²)	Cubic Root Cube Mean Wind Speed (kWh/m²)
418.56	298.58	418.56
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m²)		417.11
<i>Energy Production Results for the Second Quarter of 1987</i>		
Energy Production Parameter		
Energy Probability Function (kWh/m²)	Arithmetic Mean Wind Speed (kWh/m²)	Cubic Root Cube Mean Wind Speed (kWh/m²)
449.46	302.59	449.46
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m²)		447.76
<i>Energy Production Results for the Third Quarter of 1987</i>		
Energy Production Parameter		
Energy Probability Function (kWh/m²)	Arithmetic Mean Wind Speed (kWh/m²)	Cubic Root Cube Mean Wind Speed (kWh/m²)
481.89	353.08	481.89
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m²)		480.72
<i>Energy Production Results for the Fourth Quarter of 1987</i>		
Energy Production Parameter		
Energy Probability Function (kWh/m²)	Arithmetic Mean Wind Speed (kWh/m²)	Cubic Root Cube Mean Wind Speed (kWh/m²)
823.09	519.95	823.09
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m²)		821.79
<i>Energy Production Results for the Full Year of 1987</i>		
Energy Production Parameter		
Energy Probability Function (kWh/m²)	Arithmetic Mean Wind Speed (kWh/m²)	Cubic Root Cube Mean Wind Speed (kWh/m²)
2,191.83	1,459.06	2,191.83
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m²)		2,185.84

Table 6.4: Power Production Results.

<i>Power Production Results for the First Quarter of 1987</i>		
Power Production Parameter		
Wind Power Density (W/m²)	Arithmetic Mean Wind Speed (W/m²)	Cubic Root Cube Mean Wind Speed (W/m²)
193.80	138.23	193.78
<i>Power Production Results for the Second Quarter of 1987</i>		
Power Production Parameter		
Wind Power Density (W/m²)	Arithmetic Mean Wind Speed (W/m²)	Cubic Root Cube Mean Wind Speed (W/m²)
206.94	138.55	205.80
<i>Power Production Results for the Third Quarter of 1987</i>		
Power Production Parameter		
Wind Power Density (W/m²)	Arithmetic Mean Wind Speed (W/m²)	Cubic Root Cube Mean Wind Speed (W/m²)
219.04	159.91	218.25
<i>Power Production Results for the Fourth Quarter of 1987</i>		
Power Production Parameter		
Wind Power Density (W/m²)	Arithmetic Mean Wind Speed (W/m²)	Cubic Root Cube Mean Wind Speed (W/m²)
378.52	235.48	372.78
<i>Power Production Results for the Full Year of 1987</i>		
Power Production Parameter		
Wind Power Density (W/m²)	Arithmetic Mean Wind Speed (W/m²)	Cubic Root Cube Mean Wind Speed (W/m²)
249.91	166.56	250.21

The data analysis was made using data measured at a height of 25 meters. Since wind turbines are sited at heights greater than 50 meters, the data has to be adjusted taking into consideration the wind shear. It is expected that wind speeds at higher heights will be greater than the one measured. Using as a base the 25 meter height at which the measurements were made we can make a plot of the wind shear factor versus height. The plot in Figure 6.1 shows how the wind speed will change relative to the 25 meter base measurement.

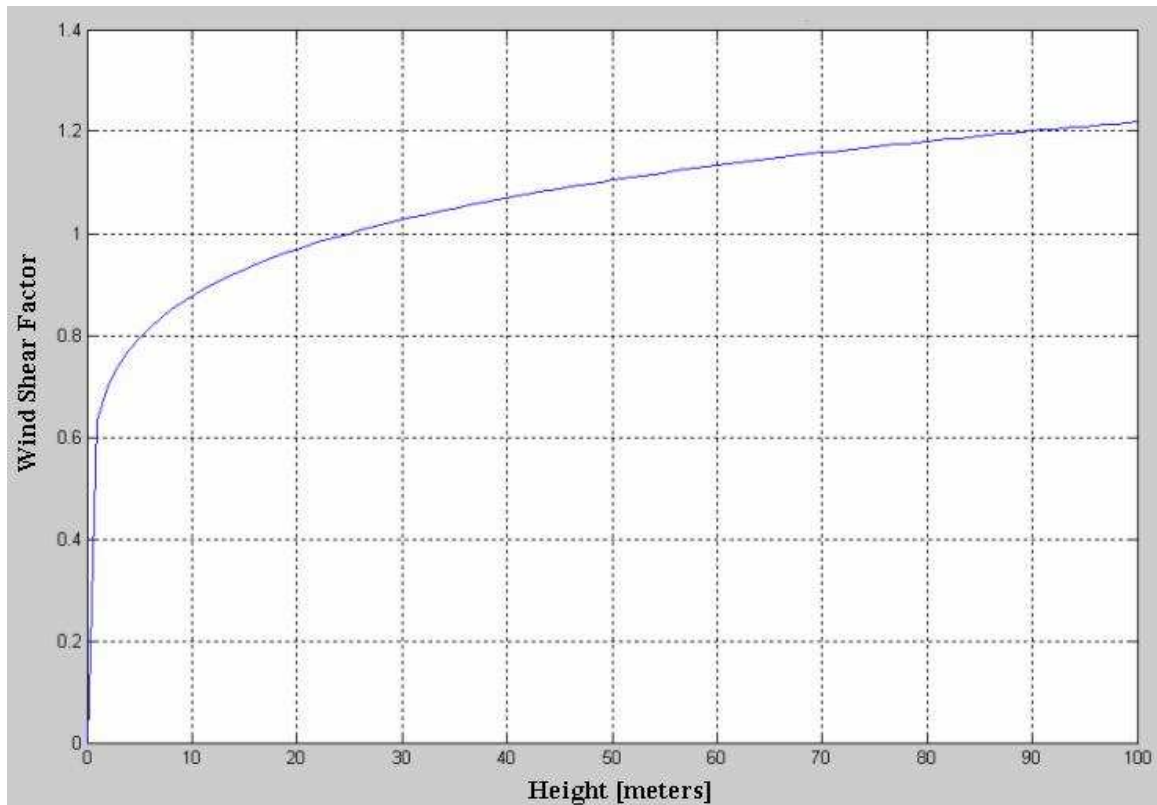


Figure 6.1: Wind Shear vs. Height (Using 1/7 Power Law).

The shear factor at 25 meters is 1, but at 100 meters is expected to be 1.22, meaning that the winds at that height will have a 22% higher wind speed than at 25 meters. The wind turbines we are considering for this project have hub heights in the range of 60 to 100 meters. In Table 6.5 we show how the wind shear affects the wind speed at the heights the wind turbines are recommended to be installed.

Table 6.5: Wind Shear Effect at Different Hub Heights.

Height (meters)	Shear Factor	Arithmetic Mean Wind Speed (m/s)	Cubic Root Cube Wind Speed (m/s)	Power Density (W/m²)
25	1.0000	6.48	7.42	250.22
60	1.1332	7.34	8.41	364.14
64	1.1437	7.41	8.49	374.35
65	1.1463	7.43	8.51	376.85
67	1.1512	7.46	8.54	381.77
68	1.1537	7.48	8.56	384.20
74	1.1677	7.57	8.66	398.38
78	1.1765	7.62	8.73	407.47
86	1.1930	7.73	8.85	424.89
92	1.2046	7.81	8.94	437.34
100	1.2190	7.90	9.05	453.26

6.1.2 Power Curves and Energy Curves

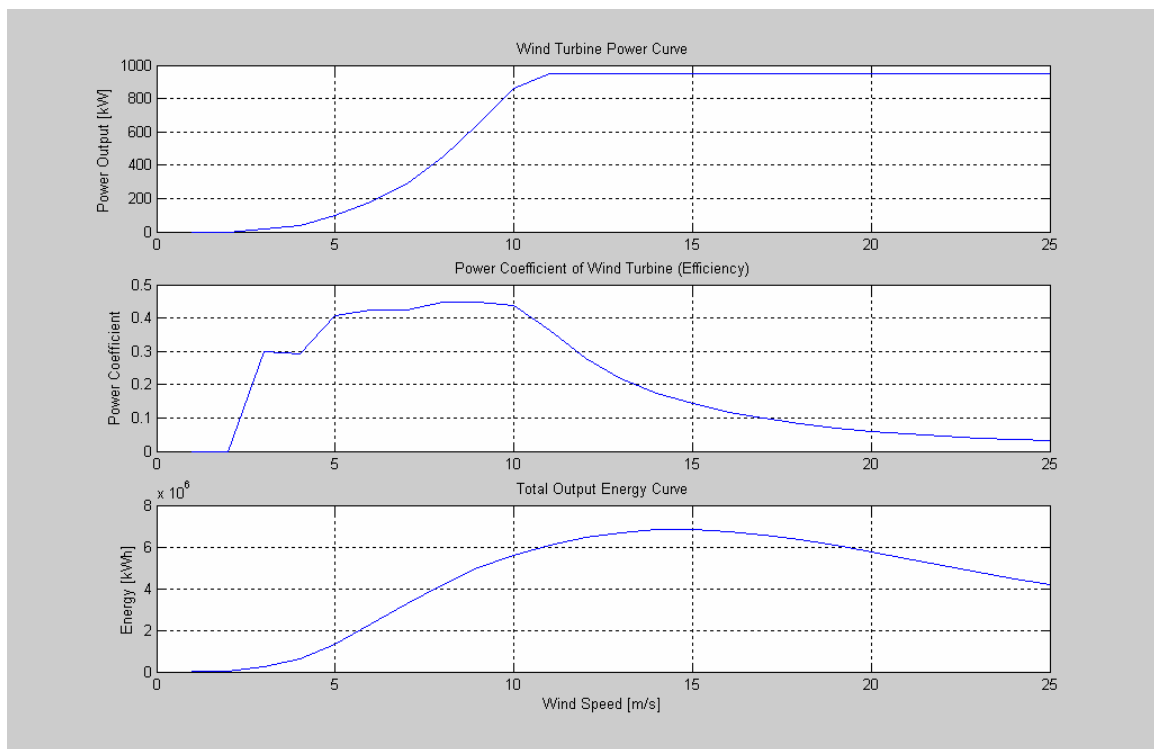
In this section we show plots of the best three turbine power curves, power coefficient and energy curves for the site. We selected seven wind turbines for the analysis. Of the selected turbines, the best three are the Suzlon S64, the DE Wind D6-1000, and the Gamesa G80. The seven selected wind turbines are tabulated in Table 6.6, the best three are highlighted in bold font. The best three turbines are identified from the results of the economic analysis that will be shown in the next sections.

For the selected site it is important to remember that the arithmetic mean average for a year is 6.48 m/s, and the site has a non height dependent yearly shape factor of 2.68. The site scale factor is height dependent and will vary with the turbine hub height.

Figures 6.2 to 6.4 show the wind turbines power curves, power coefficient curves and energy curves for the S64, the D6-1000 and the G80. Tables 6.7 to 6.12 show the energy and output power for this turbines based on the energy curve data.

Table 6.6: Turbine Information.

Turbine Information			
Manufacturer	Model	Rated Power (kW)	Rotor Sweep Area (m²)
Suzlon	S64	950	3,218
DE Wind	D6-1000	1,000	3,019
DE Wind	D6-1250	1,250	3,217
Gamesa	G52	850	2,124
Gamesa	G80	1,800	5,027
Gamesa	G83	2,000	5,411
Vestas	V66	1,750	3,421

**Figure 6.2: Power Curve, Power Coefficient and Energy Curve for S64 Wind Turbine.**

At the site 25 meters arithmetic mean wind speed, the expected average output power for a year is 315 kW, and the energy production for a year is 2.759E+06 kWh. The Suzlon S64 can be installed at 64m. Table 6.8 shows the average power output and expected energy production for that height.

Table 6.7: S64 Expected Power and Yearly Energy Production vs. Arithmetic Mean Wind Speed.

Average Wind Speed	Expected Power Output (kW)	Expected Energy Production (kWh)
1	1.89E-04	1.66E+00
2	4.73	4.14E+04
3	26.08	2.28E+05
4	73.86	6.47E+05
5	153.75	1.35E+06
6	260.17	2.28E+06
7	374.21	3.28E+06
8	479.15	4.20E+06
9	567.69	4.97E+06
10	639.12	5.60E+06
11	695.06	6.09E+06
12	736.84	6.45E+06
13	764.87	6.70E+06
14	779.25	6.83E+06
15	780.59	6.84E+06
16	770.30	6.75E+06
17	750.44	6.57E+06
18	723.30	6.34E+06
19	691.11	6.05E+06
20	655.81	5.74E+06
21	619.00	5.42E+06
22	581.89	5.10E+06
23	545.38	4.78E+06
24	510.08	4.47E+06
25	476.38	4.17E+06

Table 6.8: S64 Expected Power and Yearly Energy Production vs. Height.

Height (meters)	Power Output (kW)	Energy Production (kWh)
64	417	3.655E+06

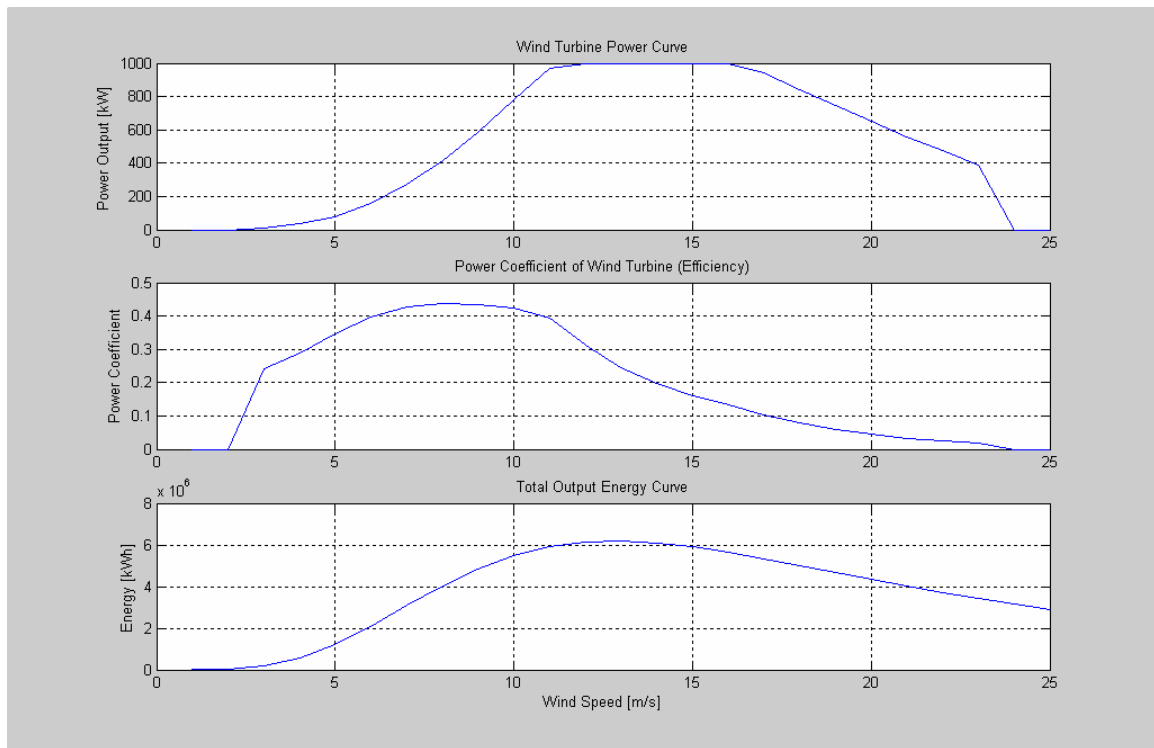


Figure 6.3: Power Curve, Power Coefficient and Energy Curve for D6 (1,000 kW) Wind Turbine.

At the site 25 meters arithmetic mean wind speed, the expected average output power for a year is 294 kW, and the energy production for a year is 2.577E+06 kWh. The DE Wind D6 (1000 kW) can be installed at 68m or 92m. Table 6.10 shows the average power output and expected energy production for those heights.

Table 6.9: D6 (1000 kW) Expected Power and Yearly Energy Production vs. Arithmetic Mean Wind Speed.

Average Wind Speed	Expected Power Output (kW)	Expected Energy Production (kWh)
1	1.42E-04	1.24E+00
2	3.73	3.27E+04
3	21.93	1.92E+05
4	64.41	5.64E+05
5	138.14	1.21E+06
6	239.59	2.10E+06
7	353.33	3.10E+06
8	462.05	4.05E+06
9	554.54	4.86E+06
10	625.61	5.48E+06
11	673.77	5.90E+06
12	699.90	6.13E+06
13	706.44	6.19E+06
14	696.88	6.10E+06
15	675.12	5.91E+06
16	644.93	5.65E+06
17	609.54	5.34E+06
18	571.52	5.01E+06
19	532.77	4.67E+06
20	494.61	4.33E+06
21	457.92	4.01E+06
22	423.22	3.71E+06
23	390.78	3.42E+06
24	360.72	3.16E+06
25	333.01	2.92E+06

Table 6.10: D6 (1000 kW) Expected Power and Yearly Energy Production vs. Height.

Height (meters)	Power Output (kW)	Energy Production (kWh)
68	406	3.552E+06
92	441	3.867E+06

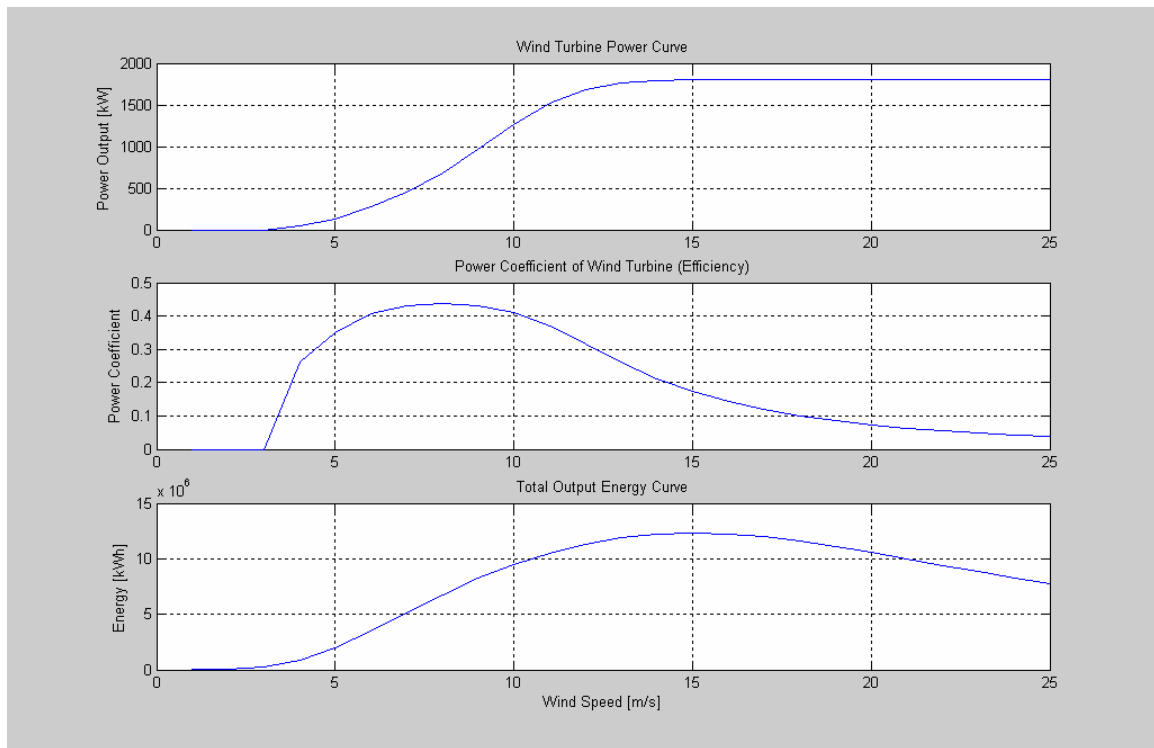


Figure 6.4: Power Curve, Power Coefficient and Energy Curve for G80 Wind Turbine.

At the site 25 meters arithmetic mean wind speed, the expected average output power for a year is 486 kW, and the energy production for a year is 4.258E+06 kWh. The Gamesa G80 can be installed at 60m, 67m, 78m or 100m. Table 6.12 shows the average power output and expected energy production for those heights.

Table 6.11: G80 Expected Power and Yearly Energy Production vs. Arithmetic Mean Wind Speed.

Average Wind Speed	Expected Power Output (kW)	Expected Energy Production (kWh)
1	1.00E-10	8.77E-07
2	1.63	1.43E+04
3	29.40	2.58E+05
4	102.98	9.02E+05
5	227.39	1.99E+06
6	395.15	3.46E+06
7	584.49	5.12E+06
8	771.28	6.76E+06
9	939.78	8.23E+06
10	1,083.60	9.49E+06
11	1,201.60	1.05E+07
12	1,293.60	1.13E+07
13	1,359.10	1.19E+07
14	1,397.50	1.22E+07
15	1,409.90	1.24E+07
16	1,399.00	1.23E+07
17	1,368.80	1.20E+07
18	1,323.70	1.16E+07
19	1,268.10	1.11E+07
20	1,205.90	1.06E+07
21	1,140.20	9.99E+06
22	1,073.30	9.40E+06
23	1,007.20	8.82E+06
24	942.89	8.26E+06
25	881.32	7.72E+06

Table 6.12: G80 Expected Power and Yearly Energy Production vs. Height.

Height (meters)	Power Output (kW)	Energy Production (kWh)
60	648	5.677E+06
67	670	5.873E+06
78	700	6.135E+06
100	753	6.593E+06

6.1.3 Discussion of Wind Data Analysis Results

Parameter Estimation Results Analysis

Comparing the parameter estimation methods we assume that the maximum likelihood estimation (MLE) method give the most precise values of the Weibull parameters. MLE asymptotically consistent, -efficient, and -unbiased properties assure that parameter estimation converge to the right values, produces the most precise estimates, and gets the right value on average.

From the observations it can be shown that the results from the MLE are similar to the “quick method” (QM) of estimation. The QM parameters are similar to fitting the data as a normal distribution. Since the QM and MLE parameters are similar, the data we analyzed seems to also fit a Normal distribution.

The quarterly results show that the Justus’ approximation parameter estimation method, compared to the MLE, over estimated the shape parameter by 0.3 to 0.6, but when the sample gets bigger, the year data case, the over estimation increases over 0.90. In the case of the scale parameter, the estimation results are very similar with differences of 0.07, except the third quarter data that shows a 0.39 difference between the MLE scale factor and the Justus’ scale factor. Estimating Weibull parameters using the Justus’ approximation may result in over estimation of the shape parameter.

The least squares (LS) method tends to underestimate the shape parameter of the Weibull distribution compared to the MLE method. The results show a difference in the shape parameter in the range of 0.35 to 0.68. On the other hand it over estimates the scale parameter. The results show a difference in the scale parameter in the range of 0.16

to 0.33. The least squares method tends to overestimate the scale parameter and underestimates the shape parameter.

Wind Speed Results Analysis

Again we assumed the MLE parameters to be the exact value of the Weibull distribution parameters. We will assume that the average wind speed calculated with the MLE parameters are the exact wind speed average value.

The quarterly average wind speeds results shows that the Justus' method overestimate the arithmetic mean and cubic root cube (CRC) mean wind speed by a small difference (approximately .10 m/s). In the year data, the arithmetic mean wind speed is similar, but there is considerable difference in the CRC mean wind speed. The Justus' method underestimates the CRC mean wind speed by 0.35; this is the same as underestimating power production by 55 W/m^2 . The LS method average wind speeds over estimates the average wind speeds calculated using MLE. The results show that appears to be a tendency for the over estimation to decrease when the sample is greater, i.e. year data, but the third quarter data showed the less difference between MLE and LS average speeds results.

In general the MLE estimates must be the most accurate. Calculating average wind speed using the parameters estimated using Justus' approximation method may overestimate the arithmetic mean wind speed and underestimate the cubic root cube (CRC) mean wind speed. Calculating average wind speed using the parameters estimated using the least squares method may overestimate the arithmetic mean and CRC mean wind speed.

Energy and Power Production Results Analysis

The results were calculated using the MLE parameters. The results show that the energy density (kWh/m^2) obtained from integrating the energy probability function from 0 to ∞ is the same as substituting the CRC mean wind speed in the energy equation (Equation 3.26) discussed in Chapter 3. This shows that if we substitute the arithmetic mean wind speed in the energy equation (Equation 3.26) we will underestimate the energy that the site may be capable of producing.

The results also show that the fourth quarter of the year is the quarter that produced more energy and the first quarter is the one that produces less energy. The expected power production for a year is 250.21 W/m^2 . It can be observed that calculating wind power density using Equation 3.36 and calculating wind power density substituting the CRC mean speed in Equation 3.23 gives similar results.

Wind Shear and Energy Curves

The wind shear results show that at heights over 60 meters the wind speeds increases over 13% with respect to the 25 meter measurement height.

From the turbines power curves and energy curves it can be observed:

- Suzlon S64 950 kW – For this turbine at wind speeds between 11 m/s and 25 m/s the wind turbine works at its maximum power. For this site the turbine will produce an average of 417 kW every year. To maximize yearly energy production the turbine should be at a height where the wind arithmetic mean speed is equal to 15 m/s.
- DE Wind D6 1000 kW – For this turbine at wind speeds between 11 m/s and 16 m/s the wind turbine works at its maximum power. For this site the turbine

will produce an average of 406 kW every year. To maximize yearly energy production the turbine should be at a height where the wind arithmetic mean speed is equal to 14 m/s.

- Gamesa G80 1.8 MW – For this turbine at wind speeds between 15 m/s and 25 m/s the wind turbine works at its maximum power. For this site the turbine will produce an average of 700 kW every year. To maximize yearly energy production the turbine should be at a height where the wind arithmetic mean speed is equal to 15 m/s.

6.2 Net Present Worth Economic Analysis Results

6.2.1 Case Studies

For the economic analysis we established two cases to be studied. One case is to study the wind farm project as being developed by a group of private investors. The second case is to study the wind farm project as being developed by an existing electric utility company.

Both cases will have similar costs, but the debt financing terms and alternatives will be different. Tables 6.13 and 6.14 show the wind farm and the economical parameters that were used for the economic analysis.

Table 6.13: Wind Farm Parameters.

Parameter	Value
Wind Farm Installed Capacity	10 MW
Wind Farm Availability Factor	98% of the time
Wind Farm Performance Derating Factor	1% yearly
Wind Farm Wear and Tear Derating Factor	0.5% decrease of previous energy output each year

Table 6.14: Economical Analysis Parameters.

Parameter	Value
Project Life	25 years
Installation Costs	\$1,400/kW installed
Operation and Maintenance (O&M) Costs	\$0.018/kWh produced
Land Costs	\$4,000/turbine installed plus 1% of the gross revenue
Energy Price	\$0.09/kWh
Minimum Attractive Rate of Return (MARR)	15%
Income Tax Rate	35%
Depreciation Method	20 years MACRS
General Inflation Rate	3%
O&M Costs Specific Inflation Rate	1%
Land Costs Specific Inflation Rate	1%
Energy Price Specific Inflation Rate	1%
Private Investor Debt Financing Terms - Loan Terms	
Debt Financing Percentage	75% of Initial Cost
Loan Interest Rate	12%
Loan Repayment Term	12 years
Utility Company Debt Financing Terms - Loan Terms	
Debt Financing Percentage	75% of Initial Cost
Loan Interest Rate	7.5%
Loan Repayment Term	20 years
Utility Company Debt Financing Terms - Bond Terms	
Bond Face Value	\$1000
Bond Maturity Time	20 years
Bond Annual Coupon Rate	5% of Bond Face Value
Flotation Costs	3% of Bond Market Price
Bond Market Price	90% of the Bond Face Value
Bond Sold	12,569 bonds

In this economic analysis environmental factors are not considered because those factors are intangibles and there is not enough information to quantify them, but it is important to know they exist and if we compare a fossil fuel electric generation facility with a wind farm the environmental factors could make a difference in the result.

As shown in the previous tables the difference between both cases will be in the debt financing method and terms. The private investor case (Case #1) was evaluated under the following conditions:

- Case 1.1 – before and after taxes net present worth analysis without inflation.
- Case 1.2 – after taxes net present worth analysis with inflation.
- Case 1.3 – after taxes net present worth analysis, adding the production tax credit incentive, with inflation.
- Case 1.4 – after taxes net present worth analysis, adding a 5-year MACRS incentive, with inflation.

The utility company case (Case #2) was evaluated under the following conditions:

- Case 2.1 – before and after taxes net present worth analysis using loan debt financing, without inflation.
- Case 2.2 – after taxes net present worth analysis using loan debt financing, with inflation.
- Case 2.3 – after taxes net present worth analysis using bond debt financing, with inflation.
- Case 2.4 – after taxes net present worth analysis using loan debt financing, adding the production tax credit incentive, with inflation.
- Case 2.5 – after taxes net present worth analysis using loan debt financing, adding a 5-year MACRS incentive, with inflation.

There are a few cases where tax incentives were considered in the analysis. The two types of incentives that we used in this economic analysis are the production tax credit (PTC) and the 5 year MACRS depreciation schedule for wind projects. The PTC actually

has a value of \$0.018/kWh produced and it's given during the first 10 years of the project. The PTC is adjusted each year for inflation using a 1% rate. The 5 year MACRS offers a depreciation schedule that permits recover the capital investment in six years, this represents higher tax deductions in the first six years of the project and reduces the effects of inflation on taxes.

In large corporations with multiple business operations when the taxable income in business is negative it becomes tax savings that can be used to deduct the taxable income generated by other business operations. In this thesis an important assumption considered in the economic analysis we present is that when the taxable income in a given year is negative we assume no revenue, so the taxes paid that year are equal to zero. The United States Internal Revenue Services (IRS) allows carrying forward up to 15 years the operating loss or carrying back for 3 years to offset the taxable income in those years. In Puerto Rico they allow to carry forward it up to 7 years. In our analysis we do not use neither the carry forward nor carry back alternative.

6.2.2 Results for Case #1 Economic Analysis

For the private investor case we performed the economic analysis using seven different wind turbines. The analysis was performed considering that the power captured by the turbines is much less at the height (25 m) the wind speed measurements were taken compared with the turbine manufacturer recommended turbine hub height. Table 6.15 shows the wind turbine average yearly output power, as given by the energy curves, for the heights of 25 m and each turbine recommended hub height, the best three turbines are highlighted in bold. Tables 6.16 to 6.18 show the case #1 economic analysis results

for the best three turbines. The results show the project net present worth (NPW), internal rate of return (IRR) and simple payback period.

Table 6.15: Wind Turbine Output Power at Different Hub Heights.

Turbine	Height	Power	Height	Power
Suzlon S64 950 kW	25 m	315 kW	64 m	417 kW
DE Wind D6 1000 kW	25 m	294 kW	68 m	406 kW
DE Wind D6 1250 kW	25 m	323 kW	68 m	455 kW
Gamesa G52 850 kW	25 m	220 kW	65 m	302 kW
Gamesa G80 1.8 MW	25 m	486 kW	78 m	700 kW
Gamesa G83 2.0 MW	25 m	529 kW	78 m	764 kW
Vestas V66 1.75 MW	25 m	385 kW	78 m	580 kW

When performing engineering economics analysis the measure of effectiveness is the method better understood by management, [Canada et al. 2004]. The NPW method is a common tool used when evaluating investments or projects. The method is easier to use when all the alternatives have the same life. NPW results are always consistent: the alternative with the highest NPW is the best.

In this work we do not consider the IRR as a measure of effectiveness. To use the rate of return for comparisons we have to use the incremental approach. Using an incremental approach when we compare seven projects (one for each different turbine) is a burdensome task. Instead we use the rate of return to obtain information of how the project is yielding a negative or positive NPW. A project with a positive or negative IRR that is near the project MARR (15%) may give an unfavorable or favorable result with a small change in one of its sensitive parameters.

The simple payback period is a quick screening measure of merit. It measures how quickly the investment is recovered without interest included. In this work the payback results are presented with the purpose of giving more information to the reader.

Table 6.16: Suzlon S64 950kW Case #1 Economic Results.

Turbine: Suzlon S64 950 kW		
Hub Height	25 m	64 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$495,659.29	\$3,729,459.21
IRR	13.655%	27.015%
Payback Period	13 years	4 years
<i>After Taxes Results:</i>		
NPW	-\$1,464,034.24	\$1,397,439.00
IRR	10.515%	19.822%
Payback Period	13.5 years	5 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	\$389,680.71	\$4,908,164.11
IRR	15.998%	29.760%
Payback Period	11.5 years	3.5 years
<i>After Taxes Results</i>		
NPW	-\$858,819.43	\$2,163,597.18
IRR	12.496%	22.019%
Payback Period	13 years	5 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$1,623,772.81	\$875,995.74
IRR	9.219%	18.465%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$458,719.46	\$3,331,548.31
IRR	13.637%	26.873%
Payback Period	12.5 years	4 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$1,292,109.53	\$1,898,885.24
IRR	10.327%	23.178%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$1,319,753.83	\$2,416,551.27
IRR	10.898%	24.43%
Payback Period	14 years	3.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$1,930,885.43	\$1,227,476.38
IRR	7.668%	20.806%

Table 6.17: DE Wind D6 1000 kW Case #1 Economic Results.

Turbine: DE Wind D6 1000 kW		
Hub Height	25 m	68 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$1,875,817.83	\$2,341,769.26
IRR	9.966%	22.498%
Payback Period	15 years	5 years
<i>After Taxes Results:</i>		
NPW	-\$2,501,678.65	\$539,652.90
IRR	7.430%	16.886%
Payback Period	15.5 years	7 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$1,125,871.16	\$3,384,557.90
IRR	12.141%	25.153%
Payback Period	14 years	4.5 years
<i>After Taxes Results</i>		
NPW	-\$1,959,676.06	\$1,217,465.52
IRR	9.327%	19.011%
Payback Period	15 years	6 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$2,507,251.59	\$135,457.79
IRR	6.142%	15.545%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$1,769,672.55	\$2,146,019.43
IRR	9.864%	22.650%
Payback Period	14 years	4.5 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$2,358,527.83	\$943,982.48
IRR	6.664%	19.078%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$2,505,282.21	\$1,233,278.66
IRR	7.415%	19.704%
Payback Period	16 years	4.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$2,898,026.80	\$262,396.02
IRR	4.286%	16.218%

Table 6.18: Gamesa G80 1.8 MW Case #1 Economic Results.

Turbine: Gamesa G80 1.8 MW		
Hub Height	25 m	78 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$2,877,841.75	\$1,957,320.59
IRR	8.051%	20.669%
Payback Period	16 years	6 years
<i>After Taxes Results:</i>		
NPW	-\$3,432,744.14	\$211,161.50
IRR	5.721%	15.674%
Payback Period	17 years	9 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$2,126,664.86	\$3,044,219.89
IRR	10.136%	23.275%
Payback Period	15 years	5 years
<i>After Taxes Results</i>		
NPW	-\$2,874,424.49	\$917,646.04
IRR	7.554%	17.763%
Payback Period	15.5 years	7 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$3,349,033.11	-\$181,381.09
IRR	4.421%	14.333%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$2,731,205.41	\$1,805,333.12
IRR	7.918%	20.817%
Payback Period	15.5 years	5 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$3,238,412.77	\$587,842.19
IRR	4.775%	17.298%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$3,474,546.55	\$824,752.58
IRR	5.607%	17.823%
Payback Period	17.5 years	5.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$3,780,171.63	-\$145,828.93
IRR	2.531%	14.392%

6.2.3 Results for Case #2 Economic Analysis

For the utility company case we performed the economical analysis using seven different wind turbines. As in Case #1, the analysis was performed considering that the power captured by the turbines is much less at the height (25 m) the wind speed measurements were taken compared with the turbine manufactures recommended turbine hub height.

It is important to remember that all the cases were examined with 75% loan debt financing, except Case 2.3 where 12,569 bonds were sold for an approximated 70% to 80% bond debt financing.

Tables 6.19 to 6.21 show the case #2 economic analysis results for the best three turbines.

Table 6.19: Suzlon S64 950 kW Case #2 Economic Results.

Turbine: Suzlon S64 950 kW		
Hub Height	25 m	64 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	\$2,369,215.30	\$6,594,333.80
IRR	25.388%	44.102%
Payback Period	4 years	2 years
<i>After Taxes Results:</i>		
NPW	\$1,079,559.29	\$3,825,886.32
IRR	20.240%	32.993%
Payback Period	4.5 years	3 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$3,254,555.29	\$7,773,038.69
IRR	27.941%	46.456%
Payback Period	4 years	2 years
<i>After Taxes Results</i>		
NPW	\$1,655,030.29	\$4,592,044.50
IRR	22.336%	34.915%
Payback Period	4.5 years	3 years
<i>After Taxes + Inflation Results</i>		
NPW	\$758,599.02	\$3,148,459.86
IRR	18.773%	30.985%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$5,290,168.22	\$9,808,651.62
IRR	39.740%	58.562%
Payback Period	3 years	1.5 years
<i>After Taxes Results</i>		
NPW	\$3,585,012.89	\$6,522,027.10
IRR	33.266%	45.739%
Payback Period	3 years	2 years
<i>After Taxes + Inflation Results</i>		
NPW	\$2,521,605.06	\$4,941,465.90
IRR	29.385%	41.494%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	\$2,449,270.24	\$5,858,086.44
IRR	26.246%	41.602%
Payback Period	3.5 years	2 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	\$1,420,682.51	\$4,263,051.39
IRR	22.569%	37.477%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	\$1,605,907.71	\$5,219,589.57
IRR	23.516%	42.808%
Payback Period	3.5 years	2 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	\$803,418.41	\$3,854,263.07
IRR	19.918%	38.648%

Table 6.20: DE Wind D6 1000 kW Case #2 Economic Results.

Turbine: DE Wind D6 1000 kW		
Hub Height	25 m	68 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	\$865,688.95	\$5,083,276.04
IRR	18.937%	38.424%
Payback Period	5.5 years	2.5 years
<i>After Taxes Results:</i>		
NPW	\$107,661.19	\$2,863,525.93
IRR	15.553%	29.183%
Payback Period	5.5 years	3 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$1,615,635.62	\$6,126,064.68
IRR	21.638%	40.809%
Payback Period	5 years	2.5 years
<i>After Taxes Results</i>		
NPW	\$604,183.52	\$3,541,338.55
IRR	17.828%	31.135%
Payback Period	5.5 years	3 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$110,550.28	\$2,310,064.61
IRR	14.396%	27.316%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$3,833,637.54	\$8,344,066.61
IRR	37.441%	60.189%
Payback Period	3 years	1.5 years
<i>After Taxes Results</i>		
NPW	\$2,785,767.40	\$5,717,546.30
IRR	32.917%	47.988%
Payback Period	3 years	2 years
<i>After Taxes + Inflation Results</i>		
NPW	\$1,972,395.86	\$4,387,943.22
IRR	29.045%	43.678%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	\$1,095,760.19	\$4,661,925.05
IRR	20.235%	37.285%
Payback Period	4.5 years	2.5 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	\$312,295.03	\$3,296,600.82
IRR	16.733%	33.286%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	\$294,393.91	\$3,982,386.80
IRR	16.612%	37.168%
Payback Period	4.5 years	2.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$281,468.11	\$2,834,708.98
IRR	13.216%	33.172%

Table 6.21: Gamesa G80 1.8MW Case #2 Economic Results.

Turbine: Gamesa G80 1.8 MW		
Hub Height	25 m	78 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	\$82,985.58	\$4,918,147.92
IRR	15.347%	35.963%
Payback Period	7 years	3 years
<i>After Taxes Results:</i>		
NPW	-\$500,557.31	\$2,720,944.37
IRR	12.619%	27.521%
Payback Period	7 years	3.5 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$834,162.46	\$6,005,047.21
IRR	18.145%	38.368%
Payback Period	6 years	2.5 years
<i>After Taxes Results</i>		
NPW	\$11,764.14	\$3,427,428.91
IRR	15.051%	29.491%
Payback Period	6 years	3 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$653,185.97	\$2,167,194.27
IRR	11.700%	25.719%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$2,727,917.28	\$7,898,802.03
IRR	27.035%	46.456%
Payback Period	4 years	2 years
<i>After Taxes Results</i>		
NPW	\$1,804,827.98	\$5,165,903.07
IRR	23.852%	37.086%
Payback Period	4.5 years	2.5 years
<i>After Taxes + Inflation Results</i>		
NPW	\$969,380.25	\$3,738,632.75
IRR	20.245%	33.094%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	\$372,081.18	\$4,579,531.68
IRR	16.629%	35.310%
Payback Period	5.5 years	3 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$347,135.28	\$3,181,033.31
IRR	13.232%	31.369%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$437,590.21	\$3,828,989.27
IRR	12.809%	34.726%
Payback Period	6 years	2.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$943,144.56	\$2,663,119.55
IRR	9.523%	30.802%

6.2.4 Summary of the Economic Analysis Results

In this section we tabulate the best results for each case and sub-case studied. For Cases 1.1 and 2.1 the results tabulated are after taxes, for the other cases the results are after taxes including inflation. The results are ordered from best net present worth result to the worst. Table 6.22 show the results for Case #1 and Table 6.23 show the results for Case #2.

Additional results for the other four wind turbines that were not considered are shown in Appendix B. In Appendix C we show pictures of the spreadsheet and cash flow diagram for the five years of the economic analysis of Cases 1.1 and 1.2 using the Suzlon S64 wind turbine.

Table 6.22: Case #1 Results Summary – Hub Height Variable.

Ranking	Turbine / Height	NPW	IRR	Payback Period
Case 1.1				
1	Suzlon S64 950 kW / 64m	\$1,397,439.00	19.822%	5 years
2	DE Wind D6 1000 kW / 68m	\$539,652.90	16.886%	7 years
3	Gamesa G80 1.8 MW / 78m	\$211,161.50	15.674%	9 years
4	Gamesa G83 2 MW / 78 m	\$36,237.21	15.124%	11.5 years
5	DE Wind D6 1250 kW / 68m	-\$471,885.02	13.419%	13 years
6	Gamesa G52 850 kW / 65m	-\$783,984.57	12.459%	13 years
7	Vestas V66 1.75 MW / 78m	-\$1,376,596.41	10.786%	14 years
Case 1.2				
1	Suzlon S64 950 kW / 64m	\$875,995.74	18.465%	5 years
2	DE Wind D6 1000 kW / 68m	\$135,457.79	15.545%	6 years
3	Gamesa G80 1.8 MW / 78m	-\$181,381.09	14.333%	7 years
4	Gamesa G83 2 MW / 78 m	-\$308,315.94	13.783%	7.5 years
5	DE Wind D6 1250 kW / 68m	-\$746,309.65	12.107%	11.5 years
6	Gamesa G52 850 kW / 65m	-\$1,026,940.67	11.146%	12 years
7	Vestas V66 1.75 MW / 78m	-\$1,551,243.78	9.484%	13 years
Case 1.3				
1	Suzlon S64 950 kW / 64m	\$1,898,885.24	23.178%	4 years
2	DE Wind D6 1000 kW / 68m	\$943,982.48	19.078%	4.5 years
3	Gamesa G80 1.8 MW / 78m	\$587,842.19	17.298%	5 years
4	Gamesa G83 2 MW / 78 m	\$355,473.23	16.483%	5.5 years
5	DE Wind D6 1250 kW / 68m	-\$225,743.96	14.091%	7 years
6	Gamesa G52 850 kW / 65m	-\$568,499.50	12.802%	8 years
7	Vestas V66 1.75 MW / 78m	-\$1,200,890.02	10.655%	12 years
Case 1.4				
1	Suzlon S64 950 kW / 64m	\$1,227,476.38	20.806%	3.5 years
2	DE Wind D6 1000 kW / 68m	\$262,396.02	16.218%	4.5 years
3	Gamesa G80 1.8 MW / 78m	-\$145,828.93	14.392%	5.5 years
4	Gamesa G83 2 MW / 78 m	-\$318,740.43	13.584%	5.5 years
5	DE Wind D6 1250 kW / 68m	-\$884,323.73	11.234%	12.5 years
6	Gamesa G52 850 kW / 65m	-\$1,226,389.09	9.998%	13 years
7	Vestas V66 1.75 MW / 78m	-\$1,847,471.04	7.978%	14 years

Table 6.23: Case #2 Summary of Results – Hub Height Variable.

Ranking	Turbine / Height	NPW	IRR	Payback Period
Case 2.1				
1	Suzlon S64 950 kW / 64m	\$3,825,886.32	32.993%	3 years
2	DE Wind D6 1000 kW / 68m	\$2,863,525.93	29.183%	3 years
3	Gamesa G80 1.8 MW / 78m	\$2,720,944.37	27.521%	3.5 years
4	Gamesa G83 2 MW / 78m	\$2,360,110.24	26.750%	3.5 years
5	DE Wind D6 1250 kW / 68m	\$1,869,102.66	24.365%	4 years
6	Gamesa G52 850 kW / 65m	\$1,624,590.28	23.013%	4 years
7	Vestas V66 1.75 MW / 78m	\$1,165,778.36	20.622%	4.5 years
Case 2.2				
1	Suzlon S64 950 kW / 64m	\$3,148,459.86	30.985%	3 years
2	DE Wind D6 1000 kW / 68m	\$2,310,064.61	27.316%	3 years
3	Gamesa G80 1.8 MW / 78m	\$2,167,194.27	25.719%	3 years
4	Gamesa G83 2 MW / 78m	\$1,866,290.87	24.980%	3.5 years
5	DE Wind D6 1250 kW / 68m	\$1,433,771.77	22.699%	3.5 years
6	Gamesa G52 850 kW / 65m	\$1,214,216.95	21.409%	4 years
7	Vestas V66 1.75 MW / 78m	\$803,300.62	19.135%	4 years
Case 2.3				
1	Suzlon S64 950 kW / 64m	\$4,941,465.90	41.494%	2 years
2	DE Wind D6 1000 kW / 68m	\$4,387,943.22	43.678%	2 years
3	Gamesa G83 2 MW / 78m	\$3,944,169.48	41.032%	2 years
4	Gamesa G80 1.8 MW / 78m	\$3,738,632.75	33.094%	2.5 years
5	DE Wind D6 1250 kW / 68m	\$3,511,650.38	38.452%	2 years
6	Gamesa G52 850 kW / 65m	\$3,165,485.53	34.555%	2.5 years
7	Vestas V66 1.75 MW / 78m	\$2,564,654.15	29.319%	3 years
Case 2.4				
1	Suzlon S64 950 kW / 64m	\$4,263,051.39	37.477%	2 years
2	DE Wind D6 1000 kW / 68m	\$3,296,600.82	33.286%	2.5 years
3	Gamesa G80 1.8 MW / 78m	\$3,181,033.31	31.369%	3 years
4	Gamesa G83 2 MW / 78m	\$2,781,001.27	30.464%	3 years
5	DE Wind D6 1250 kW / 68m	\$2,270,951.28	27.645%	3 years
6	Gamesa G52 850 kW / 65m	\$2,019,087.59	26.028%	3 years
7	Vestas V66 1.75 MW / 78m	\$1,514,196.99	23.026%	3.5 years
Case 2.5				
1	Suzlon S64 950 kW / 64m	\$3,854,263.07	38.648%	2 years
2	DE Wind D6 1000 kW / 68m	\$2,834,708.98	33.172%	2.5 years
3	Gamesa G80 1.8 MW / 78m	\$2,663,119.55	30.802%	2.5 years
4	Gamesa G83 2 MW / 78m	\$2,294,183.59	29.701%	2.5 years
5	DE Wind D6 1250 kW / 68m	\$1,732,234.96	26.103%	3 years
6	Gamesa G52 850 kW / 65m	\$1,442,500.77	24.066%	3 years
7	Vestas V66 1.75 MW / 78m	\$899,915.59	20.481%	3.5 years

The top three turbines for the above cases are shown in Table 6.24. As the results show, the turbine that for the wind conditions and economic parameters given maximizes the project net present worth is Suzlon S64 950 kW.

Table 6.24: Wind Turbines Rankings.

Rankings	Wind Turbine / Hub Height
Case 1.1, 1.2, 1.3 and 1.4: Hub Height Variable	
1	Suzlon S64 950 kW / 64m
2	DE Wind D6 1000 kW / 68m
3	Gamesa G80 1.8 MW / 78m
Case 2.1, 2.2, 2.4 and 2.5: Hub Height Variable	
1	Suzlon S64 950 kW / 10m
2	DE Wind D6 1000 kW / 68m
3	Gamesa G80 1.8 MW / 78m
Case 2.3: Hub Height Variable	
1	Suzlon S64 950 kW / 10m
2	DE Wind D6 1000 kW / 68m
3	Gamesa G83 2 MW / 78m

6.2.5 Analysis of Net Present Worth Economical Analysis Result

Case #1 Net Present Worth Analysis

In Case #1, the private investor, we compare the best three turbines as shown in Table 6.24. Case 1.1 is the simplest and in it can be observed that the income taxes has the effect of reducing the projects net present worth (NPW) an average of \$1.96M, and the internal rate of return (IRR) an average of 5.94%, and increase the project payback period of each project an average of two years no matter what wind turbine we use.

The difference between Cases 1.1 and 1.2 is that Case 1.1 is inflation free. Now in Case 1.2 the inflation is considered. In the after taxes cash flow the inflation has the effect of reducing the projects NPW an average of \$439K, and the IRR an average of 1.35%.

In Case 1.3 we add the production tax credit (PTC) to the after tax cash flow plus inflation of Case 1.2. Comparing Case 1.3 with Case 1.2, the production tax credit has the effect of increasing the projects NPW an average of \$867K, and the IRR an average of 3.74%, and decreasing the project payback period an average of 1.5 years.

In Case 1.4 we add the 5-year MACRS incentive for wind projects to the after tax cash flow plus inflation of Case 1.2. Comparing Case 1.4 with Case 1.2, the 5-year MACRS has the effect of increasing the projects NPW an average of \$171K, and the IRR an average of 1.02%, and decreasing the project payback period an average of 1.5 years.

Case #2 Net Present Worth Analysis

In Case #2, the private utility case, we compare the best three turbines as shown in Table 6.24. Case 2.1 is the simplest and in it can be observed that the income taxes has the effect of reducing the projects net present worth (NPW) an average of \$2.39M, and the internal rate of return (IRR) an average of 9.26%, and increase the project payback period of each project an average 0.67 years no matter what wind turbine we use.

The difference between Cases 2.1 and 2.2 is that Case 2.1 is inflation free. Now in Case 2.2 the inflation is considered. In the after taxes cash flow the inflation has the effect of reducing the projects NPW an average of \$595K, and the IRR an average of 1.89%.

Case 2.3 is financed with bonds, and we analyze an after tax plus inflation scenario. If we compare Case 2.3 with Case 2.2 we can observe that the project NPW increases an average of \$1.81M, and the IRR increases an average of 11.40%, and the project payback period decreases an average of 0.83 years.

In Case 2.4 we add the production tax credit (PTC) to the after tax cash flow plus inflation of Case 2.2. Comparing Case 2.4 with Case 2.2, the production tax credit has the effect of increasing the projects NPW an average of \$1.04M, and the IRR an average of 6.04%, and decreasing the project payback period an average of 0.5 year.

In Case 2.5 we add the 5-year MACRS incentive for wind projects to the after tax cash flow plus inflation of Case 1.2. Comparing Case 2.4 with Case 2.2, the 5-year MACRS has the effect of increasing the projects NPW an average of \$576K, and the IRR an average of 6.20%, and decreasing the project payback period an average of 0.67 year.

Final Remarks of the Net Present Worth Analysis

In general terms, the income taxes and the effect of the inflation on long term projects will affect significantly the projects net present worth and internal rate of return. From all the results of this project it is clear that the Suzlon S64 is the turbine which gives the best NPW or best profitable project.

Utility companies have the advantage over private investors in this type of project. Utility companies receive better financing terms and have the capital power to be able to sell bonds. These alternatives make it easier for a Utility to develop a wind farm and sell energy for a lower price than a wind farm developed by a group of private investors that do not have the same capital as utility companies.

In Table 6.16 to Table 6.21 it can be observed that for some cases if the wind speed at the turbine hub height is similar to the wind speed measured at a 25 meter height some case #1 and #2 sub cases would not be profitable. None of the case #1 projects would be profitable. All of the Suzlon S64 case #2 projects are profitable. For the DE Wind D6 and the Gamesa G80 all the Case 2.3 projects are profitable. The DE Wind D6 Case 2.2

project will be profitable if a production tax credit is given to it as shown in Case 2.4 results. This difference in wind speed shows the importance of a precise wind measurement in the site where the turbines will be installed.

There is a question still to be answered: What incentive is better? The PTC or the 5-year MACRS? The answer will depend on the cash flow of the project. If in the first years of the project the taxable income is negative then it is an advantage to have the PTC over the MARR. The reason for this is if there is not an option to carry forward losses, i.e. get a tax credit with a negative taxable income, then the 5-year MACRS will be unused and after the first six years there will be no more depreciation deductions that allow the investor to get protected from taxes. Our results show that there is a typical pattern in which the PTC is preferred when the NPW results IRR is near the project MARR. When NPW results IRR is much higher than the project MARR then the 5-year MACRS is preferred.

In Table 6.23 it can be observed that for Case 2.3 the turbine with the second highest NPW has a higher IRR than the turbine with the highest NPW. This may confuse some readers that may think that is an error, but it is not. The NPW is an absolute (dollar) measurement of an investment worth. The IRR is a relative (percentage) measure and cannot be interpreted in the same way as the NPW, [Park 1997].

Since in this project we have a minimum attractive rate of return (MARR) of 15%, we can use the IRR to observe if our project is over that MARR thus resulting in a positive NPW, or if the project is under that MARR the IRR shows how close or far the project is from the MARR helping the investor to make decisions to reach the MARR.

6.3 Economic Sensitivity Analysis Results

6.3.1 Introduction

Sensitivity analysis for the economic results was performed for the best turbine of Cases 1.1, 2.1 and 2.3. From Table 6.24 we can observe that the best turbine for all the cases was the Suzlon S64 of 950 kW. The sensitivity analysis of this turbine was made at its suggested hub height.

The sensitivity analysis in this section is divided in single-parameter sensitivity analysis and two-parameter sensitivity analysis. The single-parameter analysis was made for the after tax scenario without inflation. The two-parameter analysis was made for the before tax scenario without inflation. The objective of the single-parameter sensitivity analysis is to observe how the project net present worth changes when only one parameter increases or decreases its value. In the two-parameter sensitivity analysis we can observe how the net present worth changes when two parameters change their value at the same time.

6.3.2 Single-Parameter Sensitivity Analysis Results and Discussion

In the first case we present the after tax sensitivity analysis for Case 1.1. Case 1.1 is one of the private investor cases, financed with 75% loan debt financing at 12% interest rate for 12 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.5 to 6.9 show the sensitivity analysis results for Case 1.1.

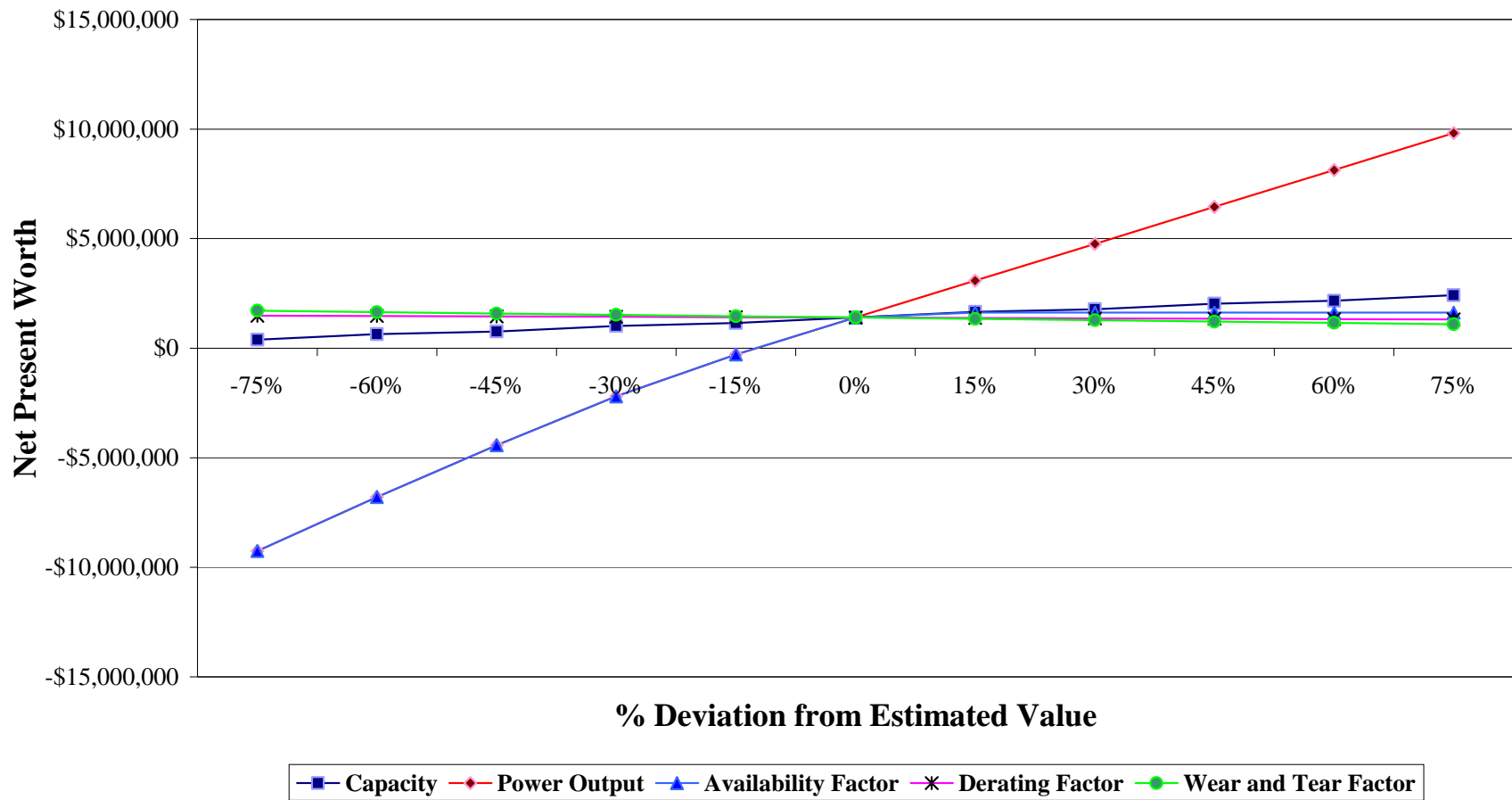


Figure 6.5: Case 1.1 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output, Availability Factor, Power Derating Factor, and Wear and Tear Factor.

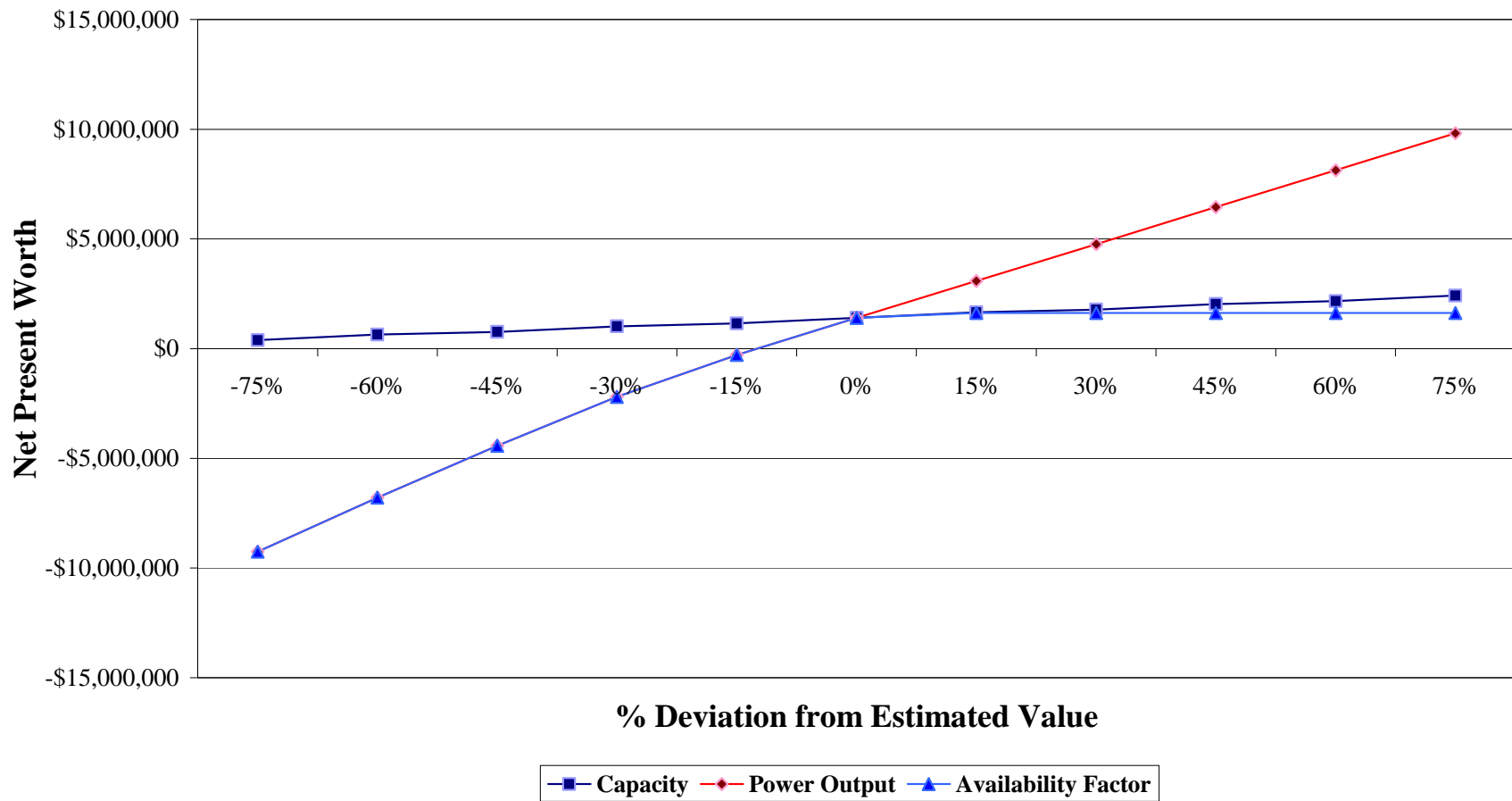


Figure 6.6: Case 1.1 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output and Availability Factor.

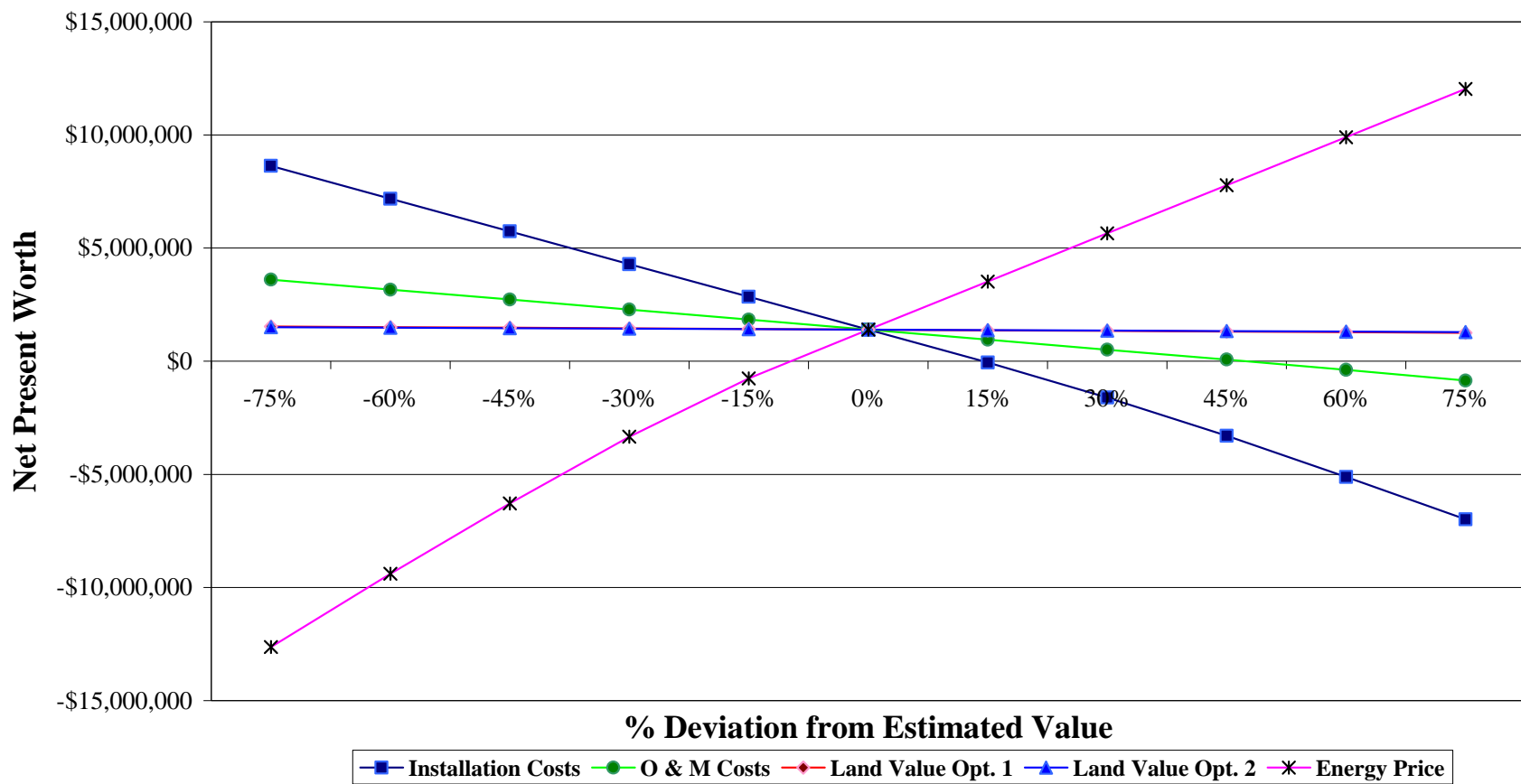


Figure 6.7: Case 1.1 Suzlon S64 Sensitivity Curves for the Parameters: Installation Cost, O&M Cost, Land Cost, and Energy Price.

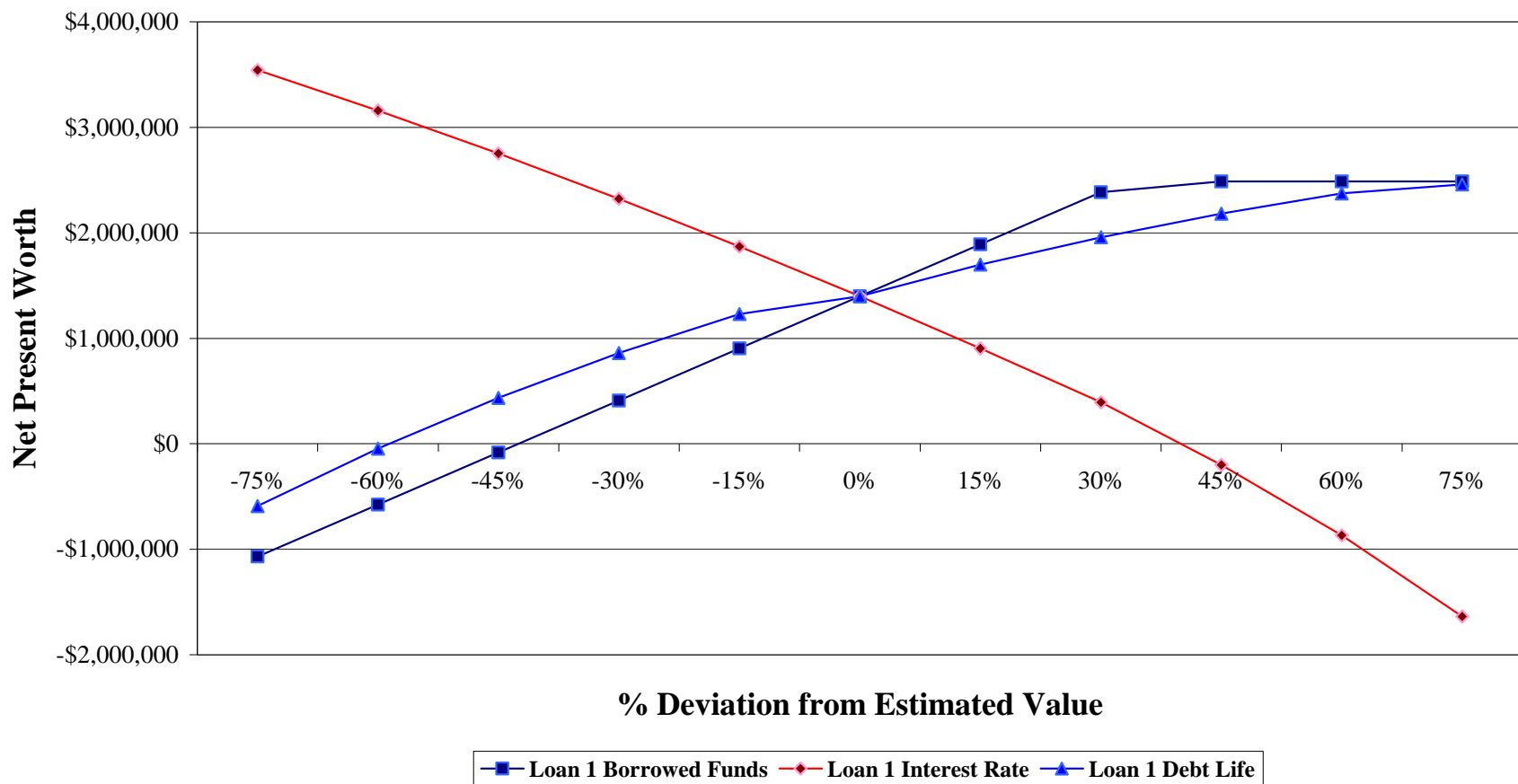


Figure 6.8: Case 1.1 Suzlon S64 Sensitivity Curves for the Parameters: Percentage of Loan Financing, Loan Interest Rate, and Loan Life.

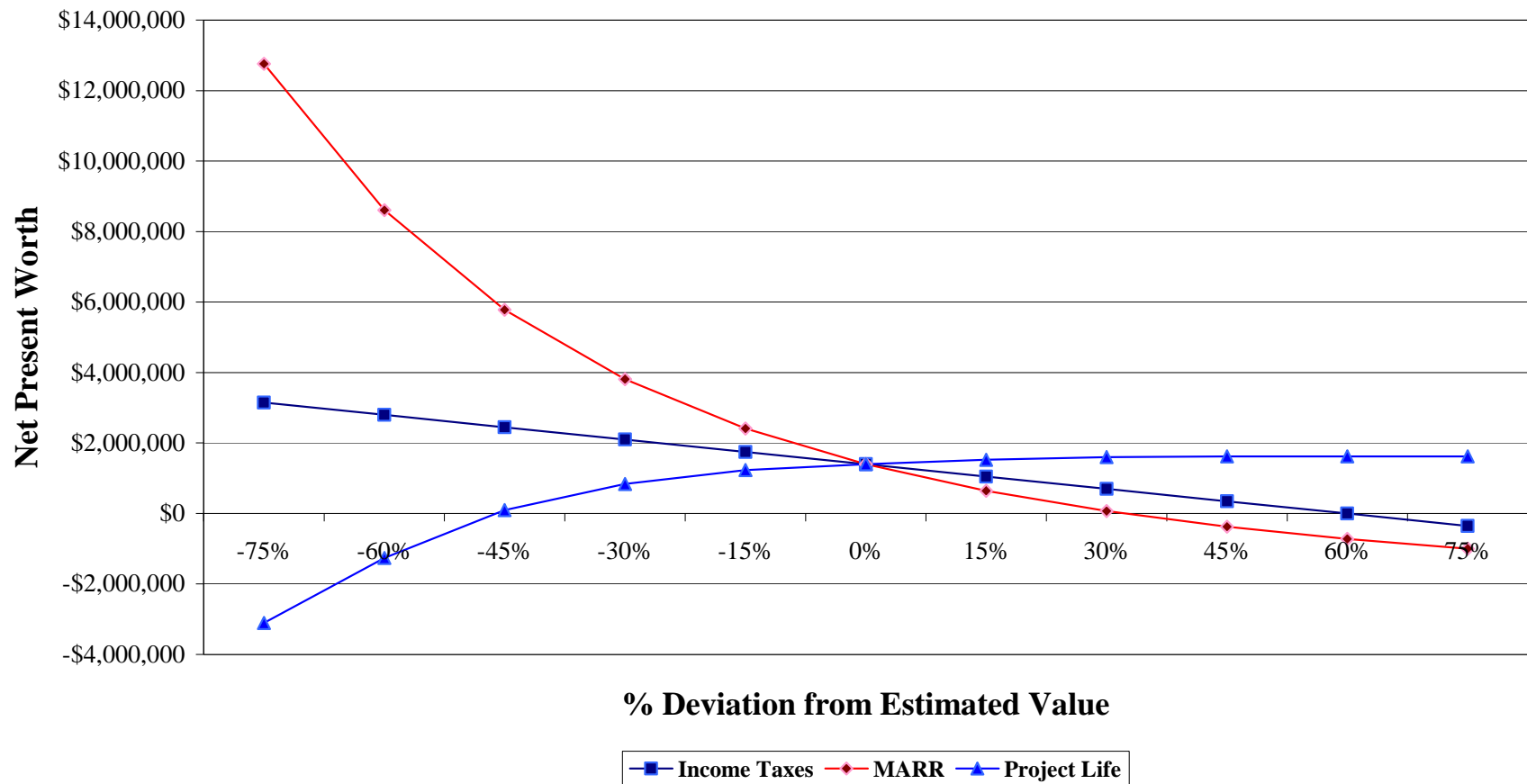


Figure 6.9: Suzlon S64 Sensitivity Graphics Curves for the Parameters: Income Taxes, Minimum Attractive Rate of Return, and Project Life.

In the second case we present the after tax sensitivity analysis for Case 2.1. Case 2.1 is one of the private utility cases, financed with a 75% loan debt financing at 7.5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.10 to 6.14 show the sensitivity analysis results for Case 2.1.

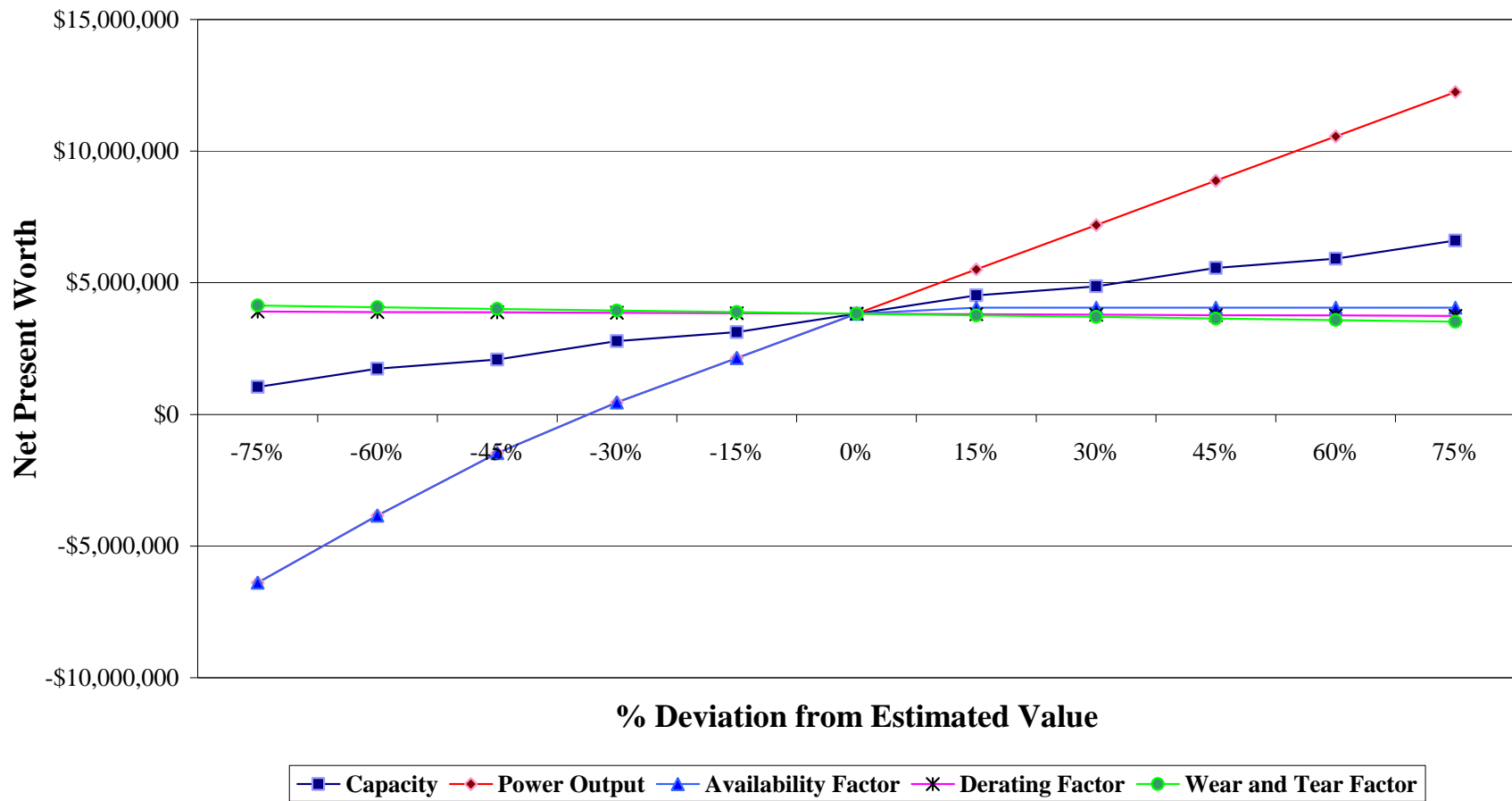


Figure 6.10: Case 2.1 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output, Availability Factor, Power Derating Factor, and Wear and Tear Factor.

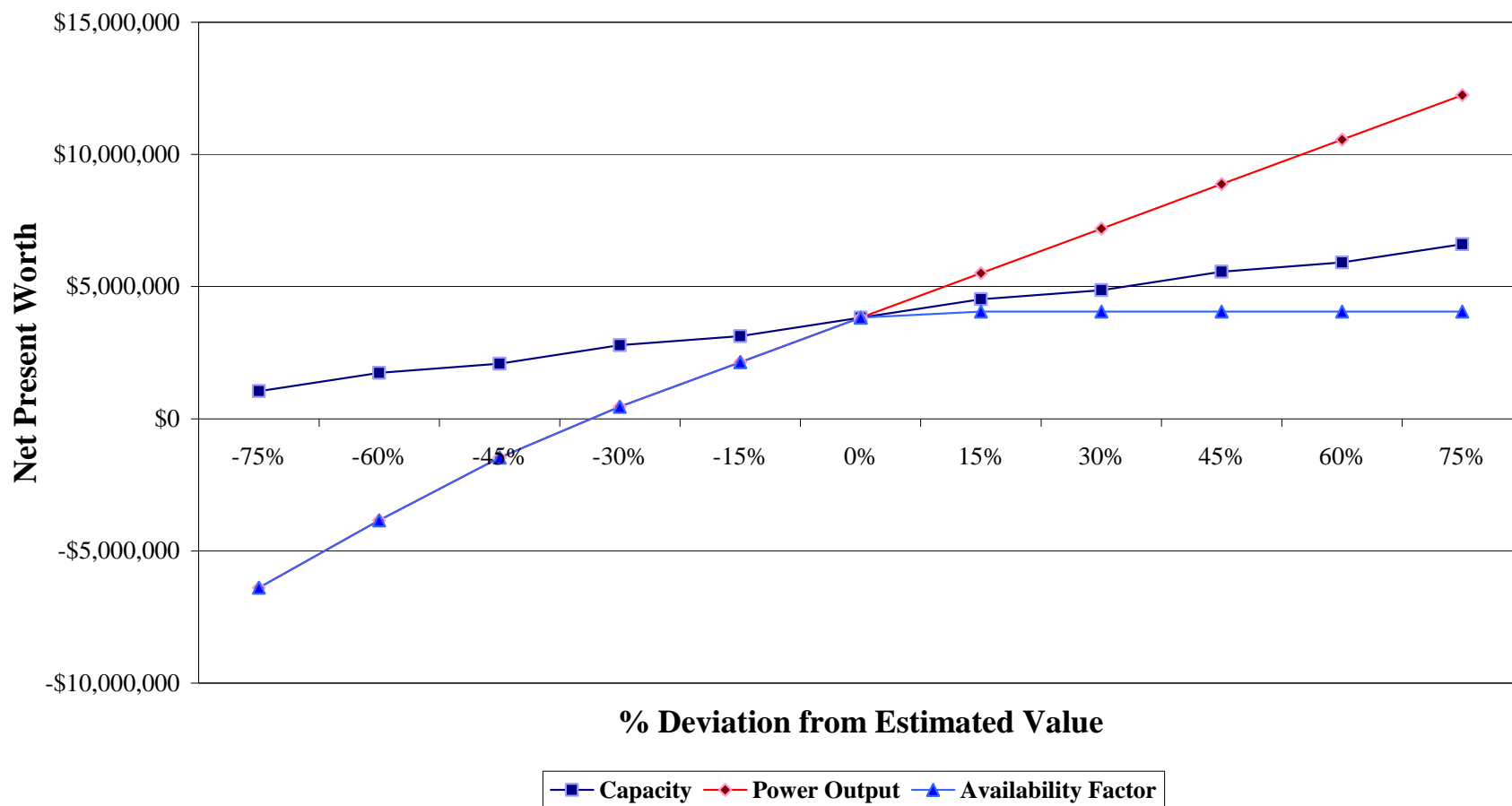


Figure 6.11: Case 2.1 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output, and Availability Factor.

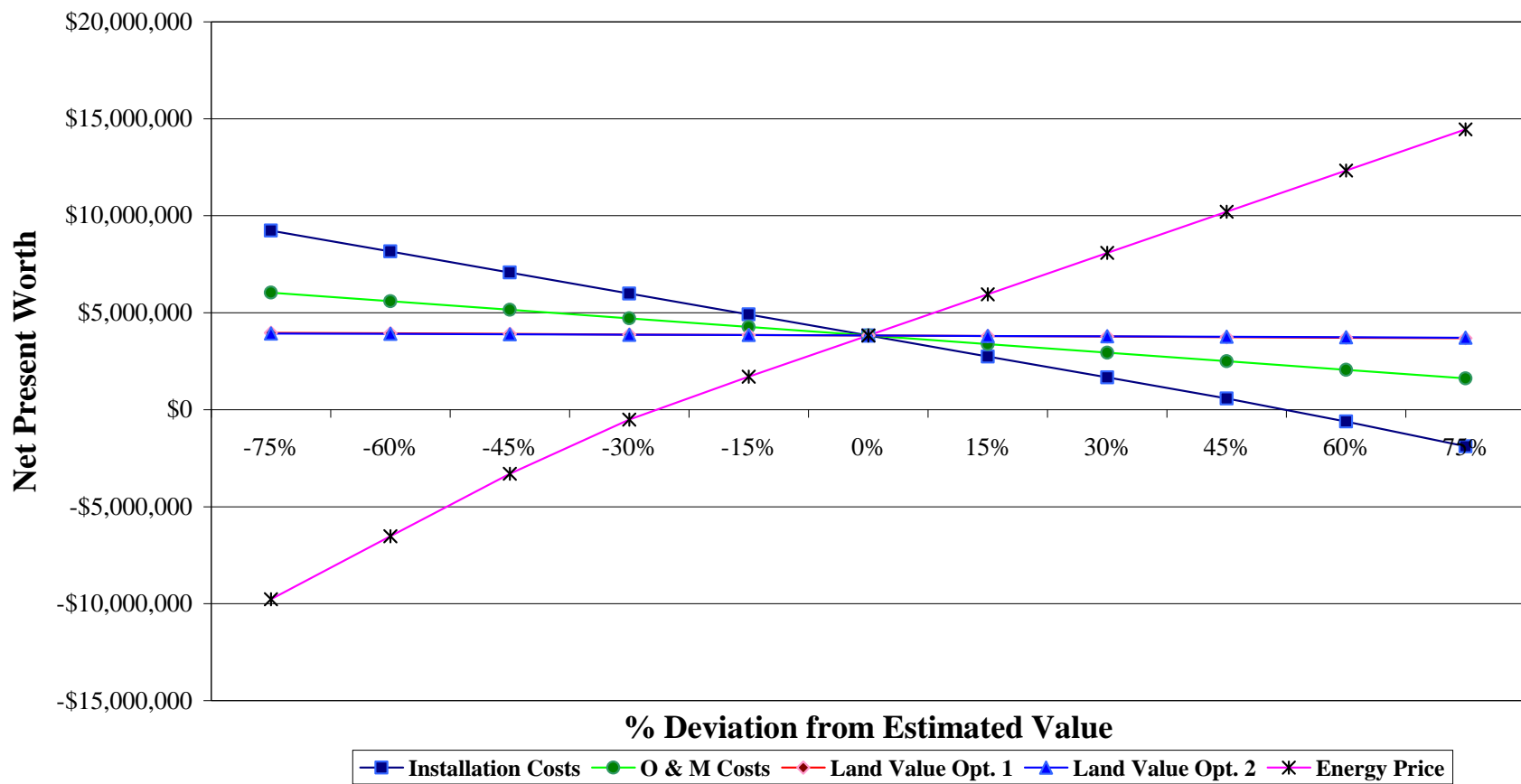


Figure 6.12: Case 2.1 Suzlon S64 Sensitivity Curves for the Parameters: Installation Cost, O&M Cost, Land Cost, and Energy Price.

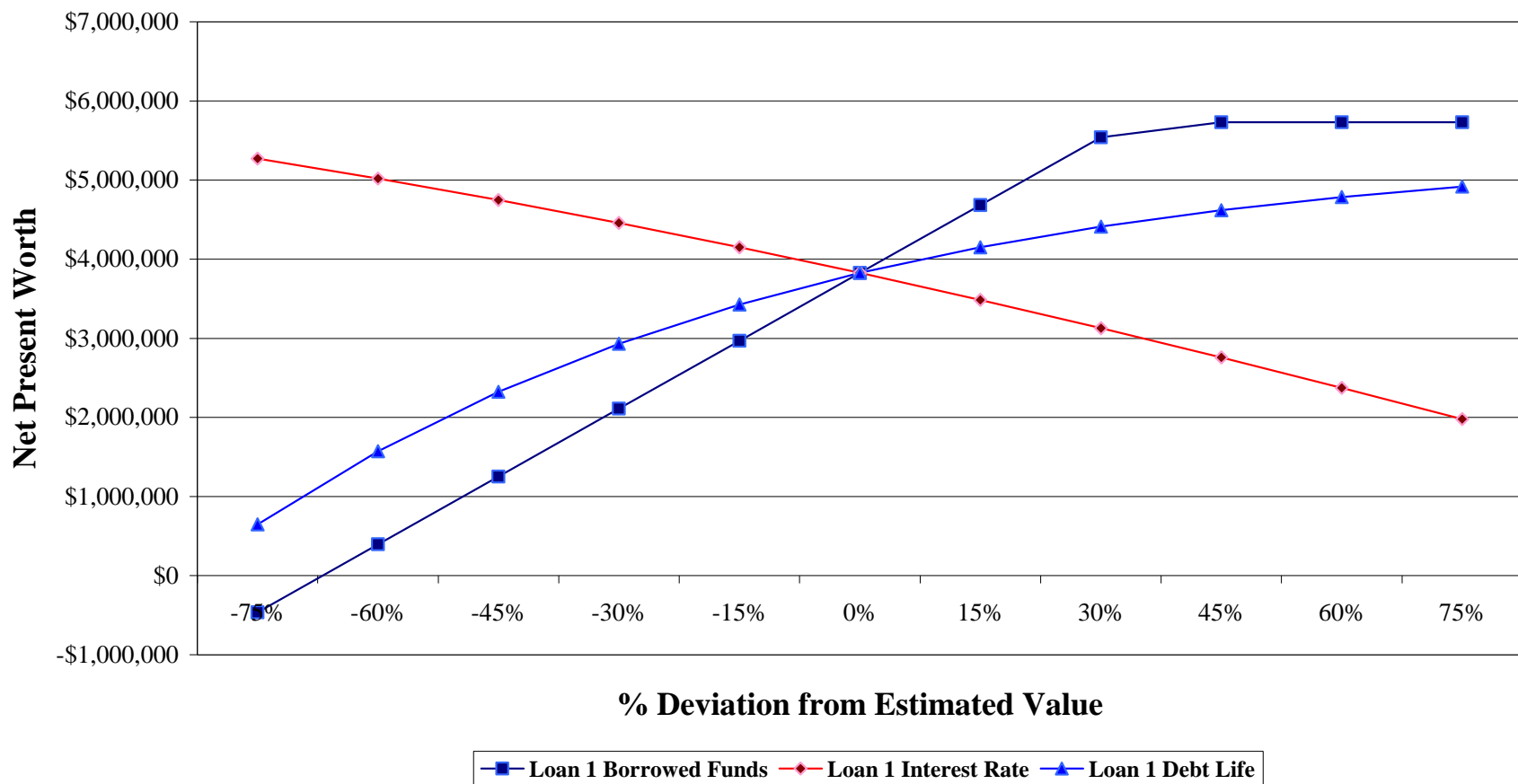


Figure 6.13: Case 2.1 Suzlon S64 Sensitivity Curves for the Parameters: Percentage of Loan Financing, Loan Interest Rate, and Loan Life.

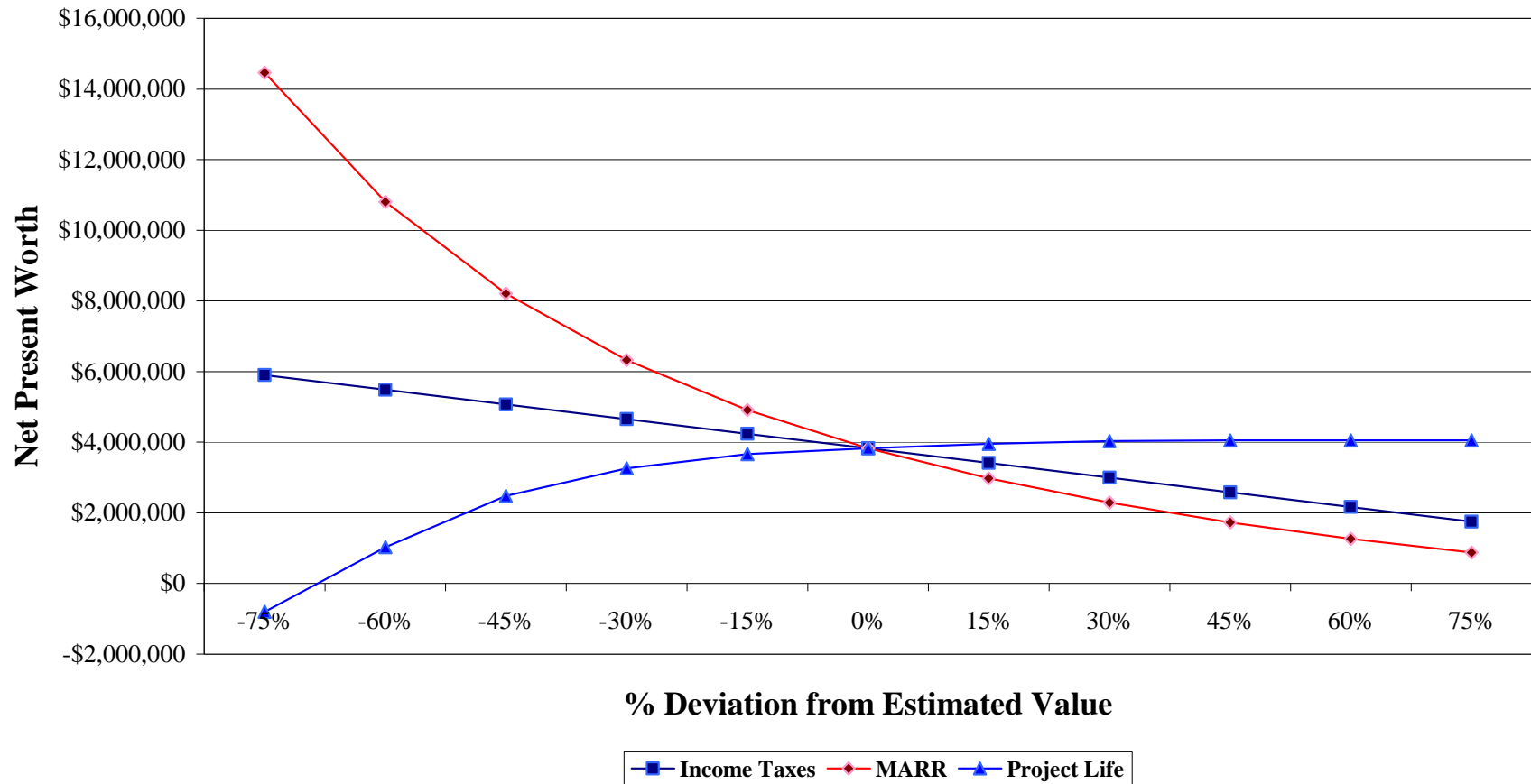


Figure 6.14: Case 2.1 Suzlon S64 Sensitivity Graphics Curves for the Parameters: Income Taxes, Minimum Attractive Rate of Return, and Project Life.

In the third case we present the after tax sensitivity analysis for Case 2.3. Case 2.3 is one of the private utility cases, financed with an approximated 75% bond debt financing at 5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.15 to 6.19 show the sensitivity analysis results for Case 2.2.

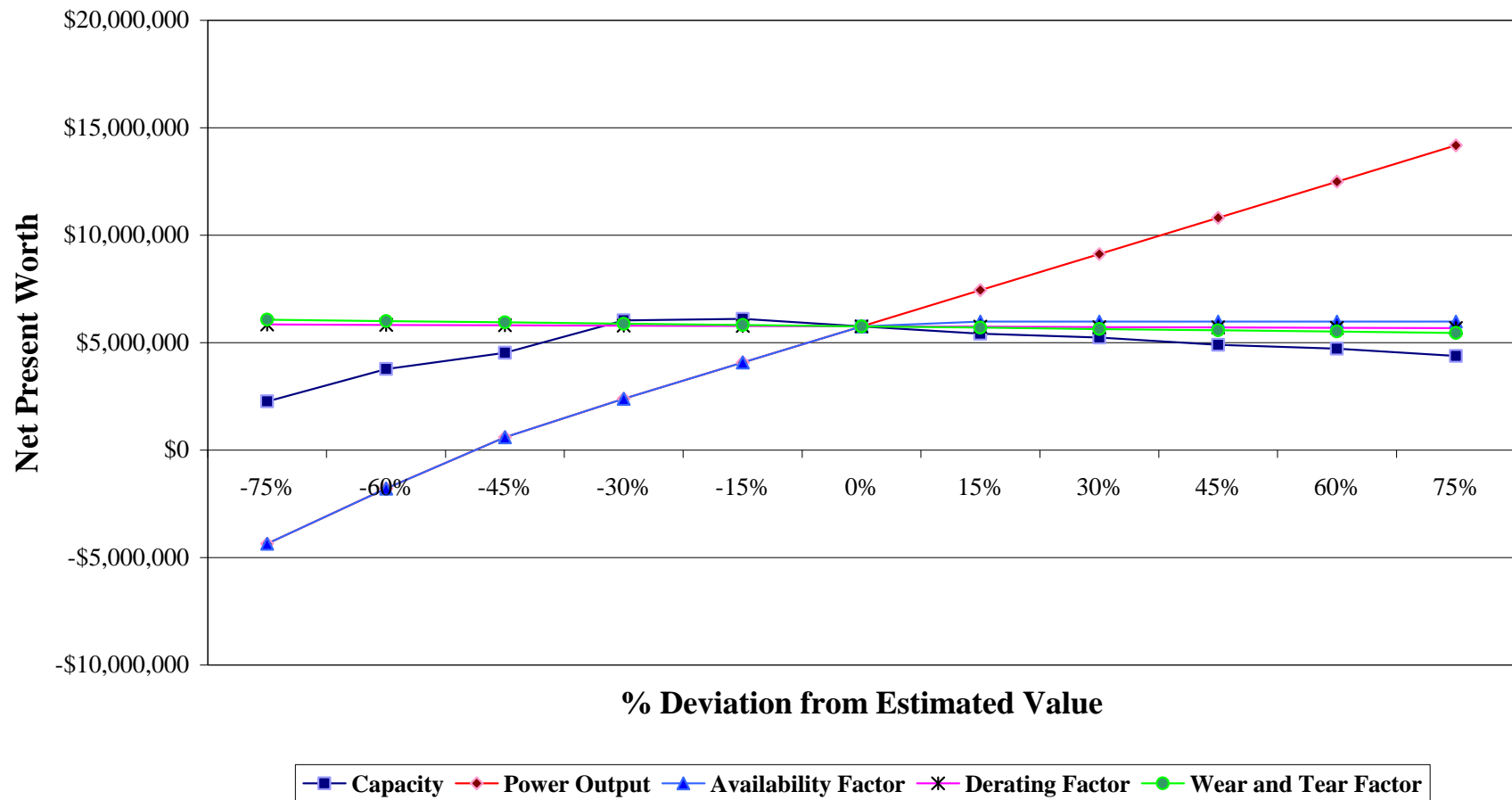


Figure 6.15: Case 2.3 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output, Availability Factor, Power Derating Factor, and Wear and Tear Factor.

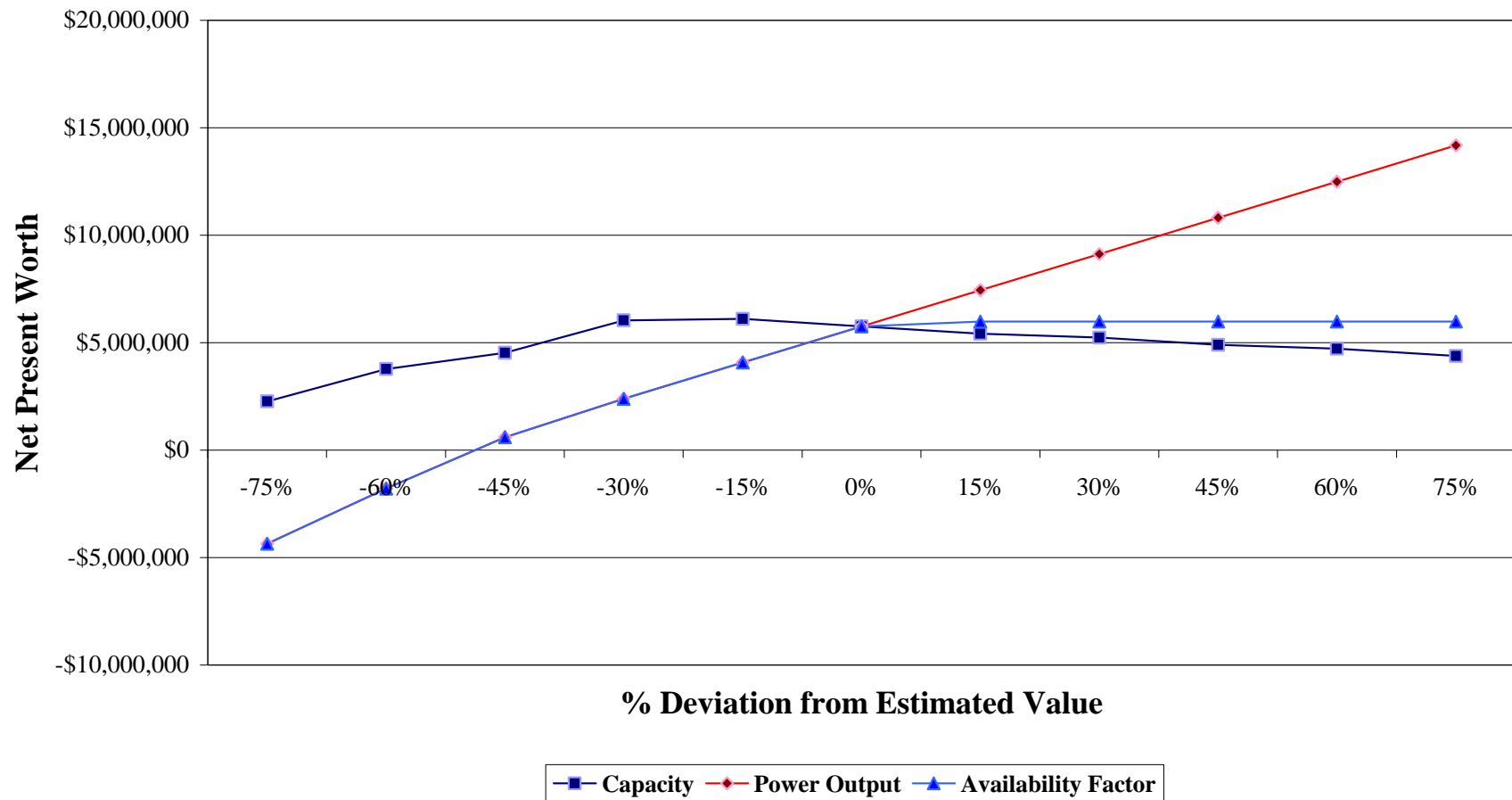


Figure 6.16: Case 2.3 Suzlon S64 Sensitivity Curves for the Parameters: Installed Capacity, Average Power Output, and Availability Factor.

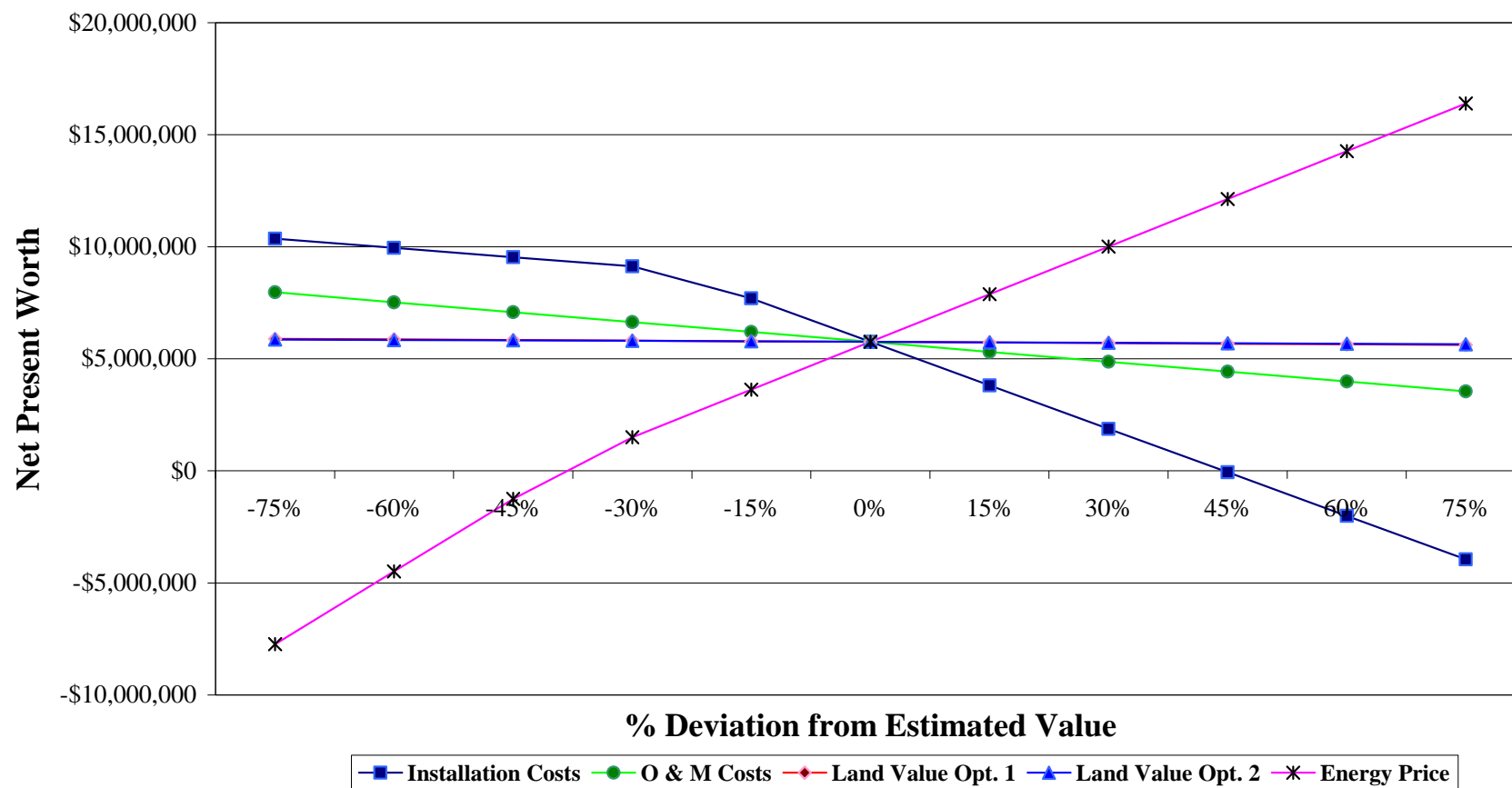


Figure 6.17: Case 2.3 Suzlon S64 Sensitivity Curves for the Parameters: Installation Cost, O&M Cost, Land Cost, and Energy Price.

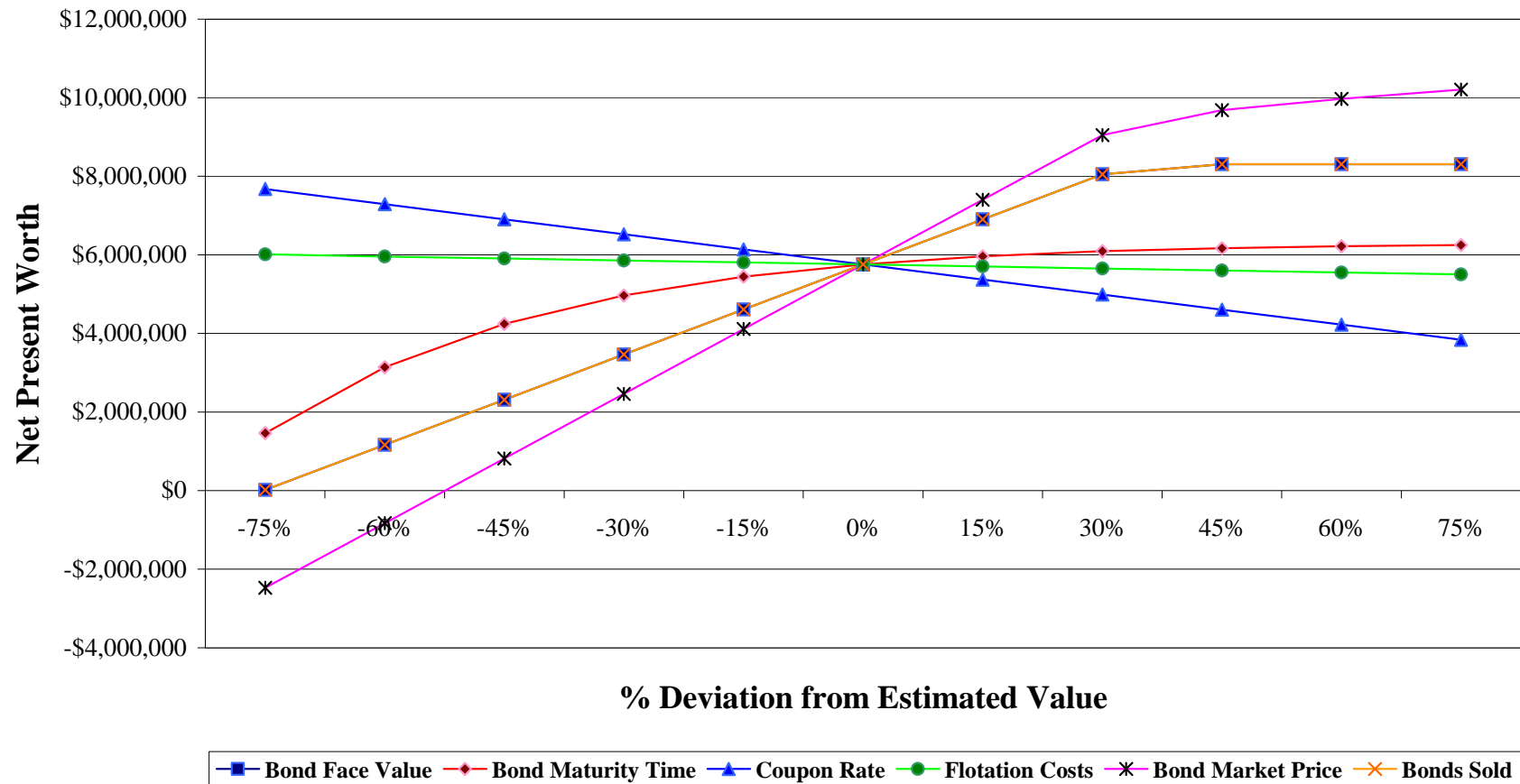


Figure 6.18: Case 2.3 Suzlon S64 Sensitivity Curves for the Parameters: Bond Face Value, Bond Maturity Time, Bond Coupon Rate, Flotation Costs, Bond Market Price, # of Bonds Sold.

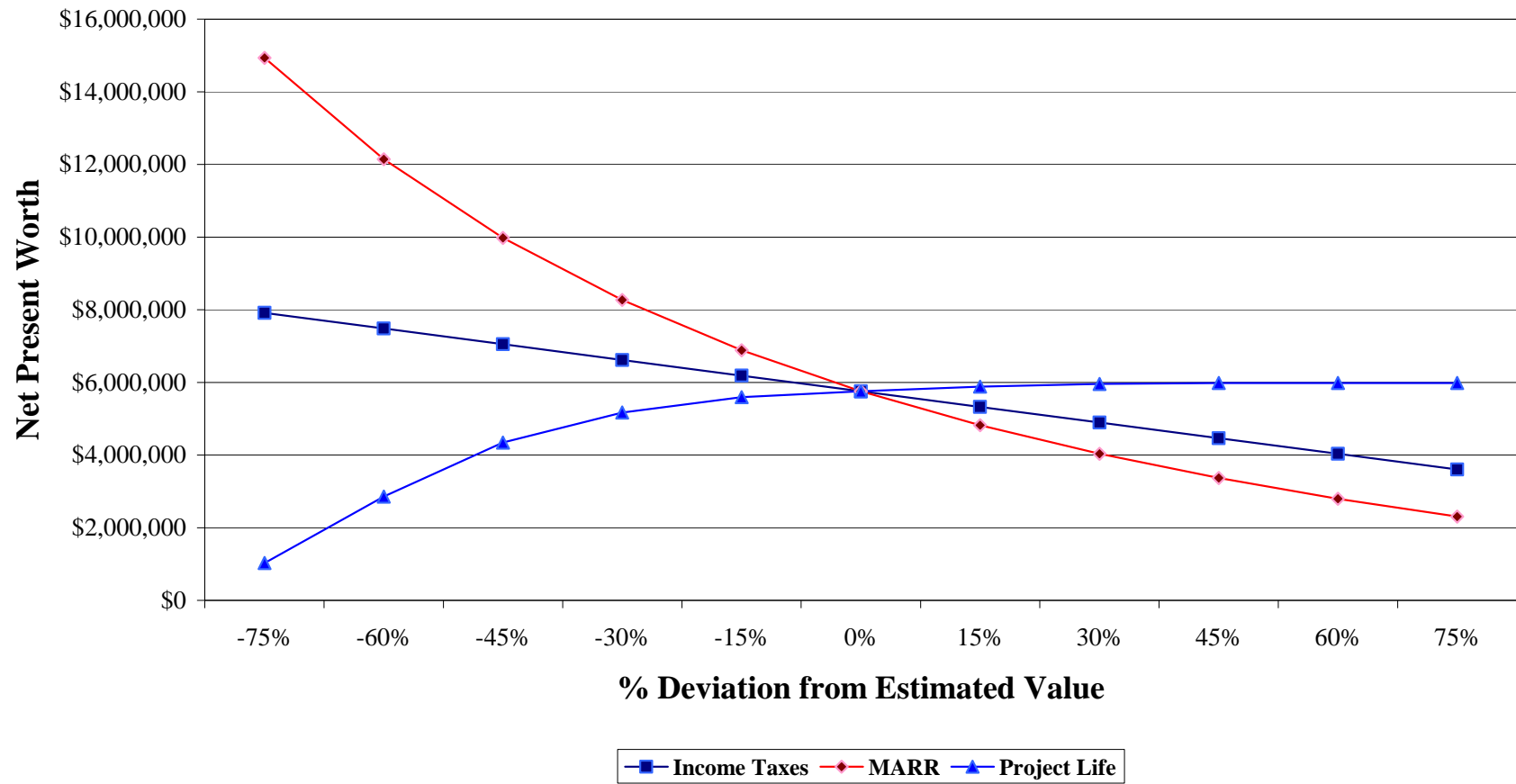


Figure 6.19: Suzlon S64 Sensitivity Graphics Curves for the Parameters: Income Taxes, Minimum Attractive Rate of Return, and Project Life.

Analysis of Single Parameter Sensitivity Results

The Suzlon S64 was used as an example to show the sensitivity of the wind farm project economic analysis. From Case 1.1, Case 2.1 and Case 2.3 after tax sensitivity curves it can be observed that the variables derating factor, wear and tear factor and land costs practically are not sensitive and changes in the value of those variables slightly change the net present worth result. Some of the most sensitive parameters are the turbine average power output, the wind farm availability factor, the energy price, wind farm installation costs, the interest rate and the number of bonds sold. Changes in those variables can affect the outcome of the project. In Table 6.25 we mention all the parameters and classify them as high-, medium-, and low- sensitivity parameters. In Table 6.26 we show what changes in some of the most sensitive parameters affect the outcome of the project.

The sensitivity analysis shows that the project most sensitive parameter is the energy price. Making small increasing changes in the energy price we can make any of the negative NPW cases we have studied a favorable one. Also reducing the energy price to obtain a NPW with an IRR near the selected MARR can help ensure that the all the energy produced by the wind farm is sold and be more competitive in the energy market..

The data in Table 6.26 shows that in Case 2.1 the parameters are less sensitive than in case 1.1. This is because Case 2.1 has a higher NPW result compared to Case 1.1. The same happens between Cases 2.1 and 2.3. Case 2.3 presents parameters less sensitive than Case 2.1, and Case 2.3 has a higher NPW result that Case 2.1.

Table 6.25: Sensitivity of the Economic Analysis Parameters.

Parameter Sensitivity		
High	Medium	Low
Power Output	Income Taxes	Land Costs
Availability Factor	Project Life	Bond Flotation Costs
Energy Price	Installed Capacity	Derating Factor
Installation Costs	O&M Costs	Wear and Tear Factor
MARR	Bond Maturity Time	-
Loan Interest Rate	Bond Coupon Rate	-
Loan Life	-	-
Borrowed Funds	-	-
Bond Market Price	-	-
Number of Bonds Sold	-	-
Bond Face Value		

Table 6.26: Most Sensitivity Parameters Break-Even Results.

Parameters	% Change for Break-Even		
	Case 1.1	Case 2.1	Case 2.3
Power Output	-12 %	-33 %	-49 %
Availability Factor	-12 %	-33 %	-49 %
Energy Price	-10 %	-26 %	-38 %
Installation Costs	+14 %	+52 %	+44 %
MARR	+32 %	> +75 %	> +75 %
Loan Interest Rate	+40 %	> +75 %	N/A
Loan Life	-58 %	< -75 %	N/A
Borrowed Funds	-42 %	-66 %	N/A
Bond Market Price	N/A	N/A	-52 %
Bonds Sold	N/A	N/A	< -75 %
Bond Face Value	N/A	N/A	< -75 %

6.3.3 Two-Parameter Sensitivity Analysis Results and Discussion

In the two parameter sensitivity analysis we present four curves for each case. The cases are the same (1.1, 2.1 and 2.3). The curves are the following:

- Change in Energy Price vs. Change in Annual Loan Payment
- Change in Energy Price vs. Change in O&M Cost
- Change in Energy Price vs. Change in Land Cost
- Change in Annual Loan Payment vs. Change in O&M Cost

In the first case we present the before tax two-parameter sensitivity analysis for Case 1.1. Case 1.1 is one of the private investor cases, financed with 75% loan debt financing at 12% interest rate for 12 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.20 to 6.23 show the two-parameter sensitivity analysis results for Case 1.1.

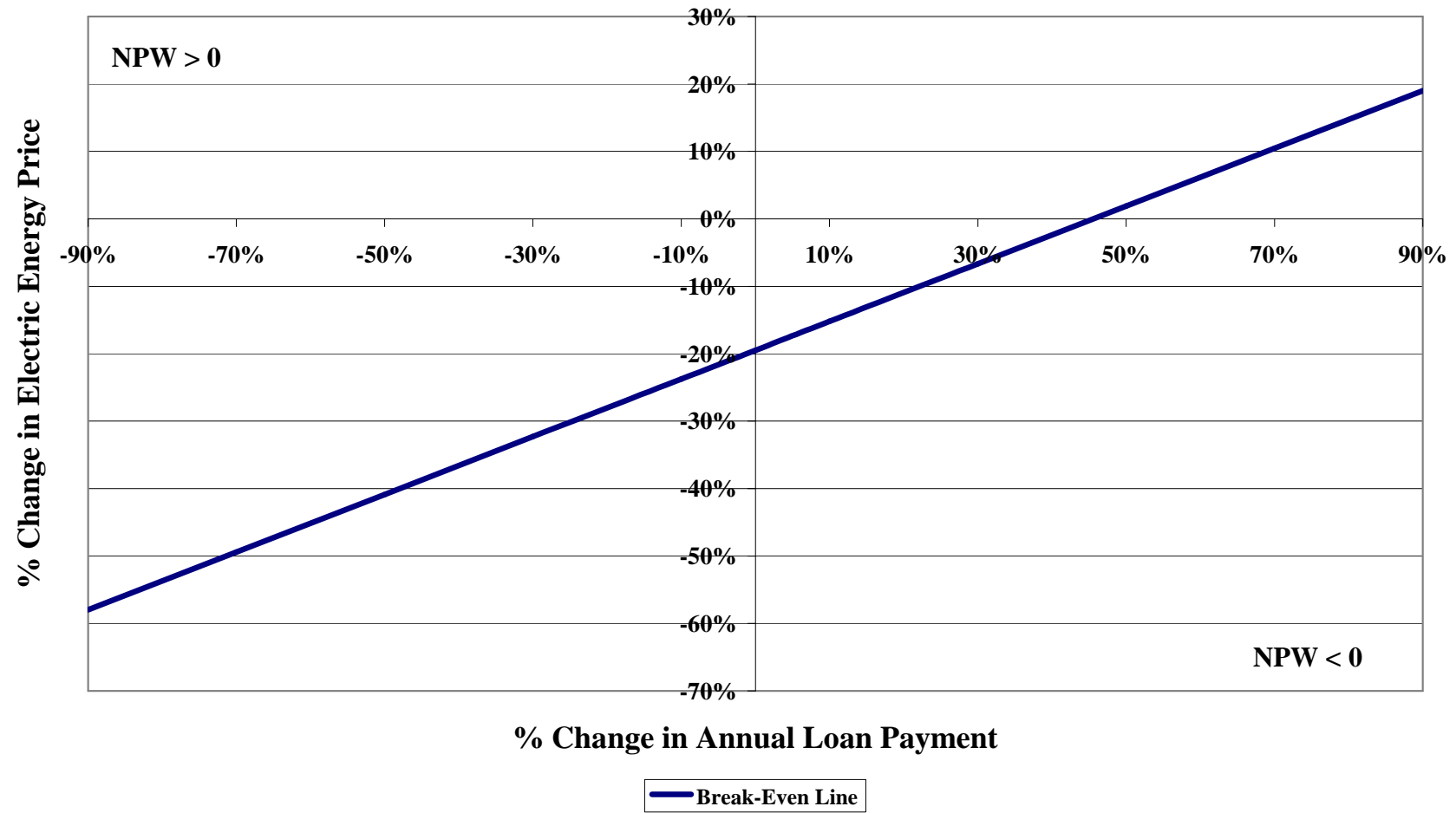


Figure 6.20: Case 1.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Annual Loan Payment.

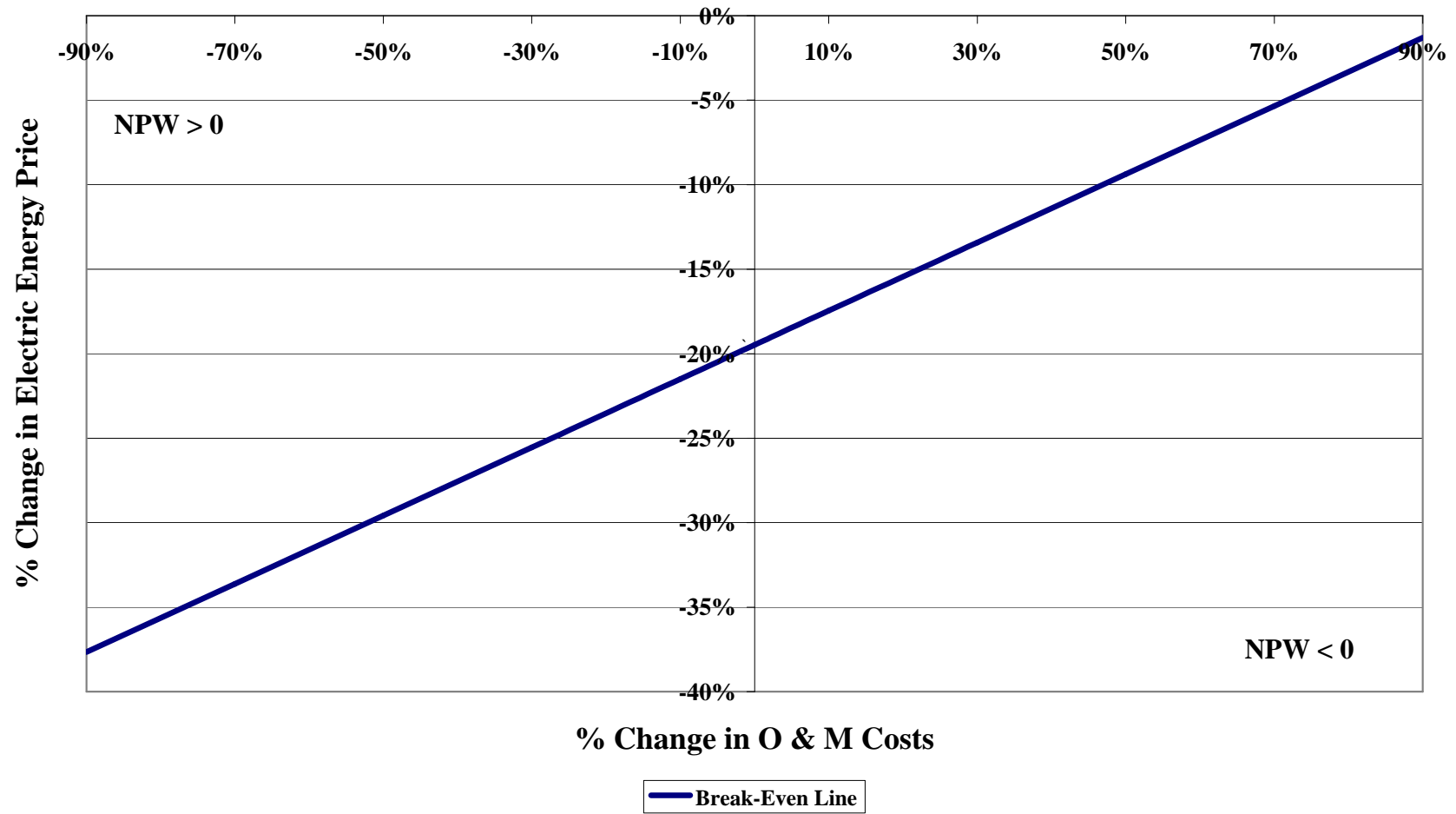


Figure 6.21: Case 1.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. O&M Cost.



Figure 6.22: Case 1.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Land Cost.

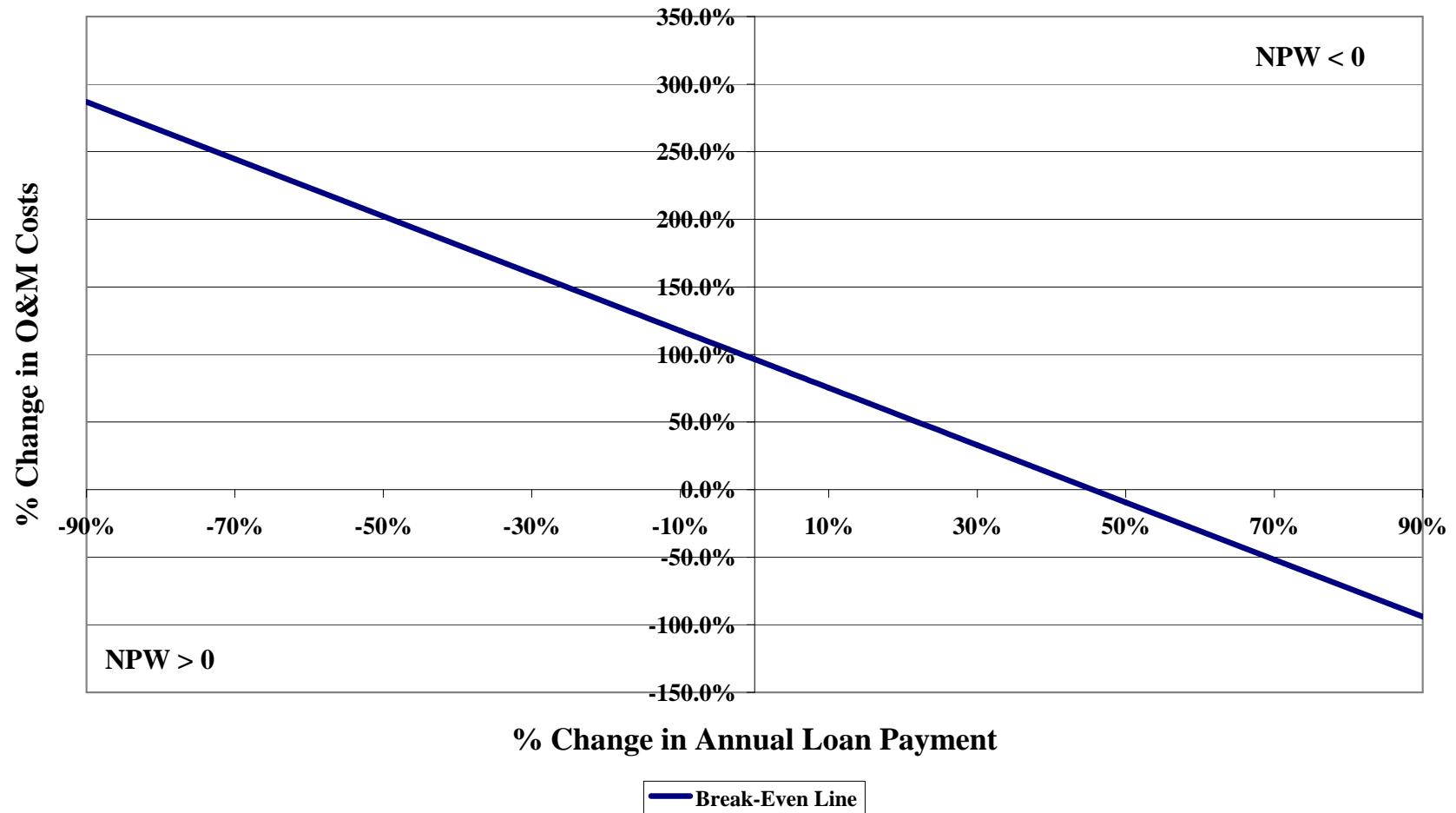


Figure 6.23: Case 1.1 Suzlon S64 Two-Parameter Sensitivity Curve: O&M Cost vs. Annual Loan Payment.

In the second case we present the before tax two-parameter sensitivity analysis for Case 2.1. Case 2.1 is one of the private investor cases, financed with 75% loan debt financing at 7.5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.24 to 6.27 show the two-parameter sensitivity analysis results for Case 2.1.

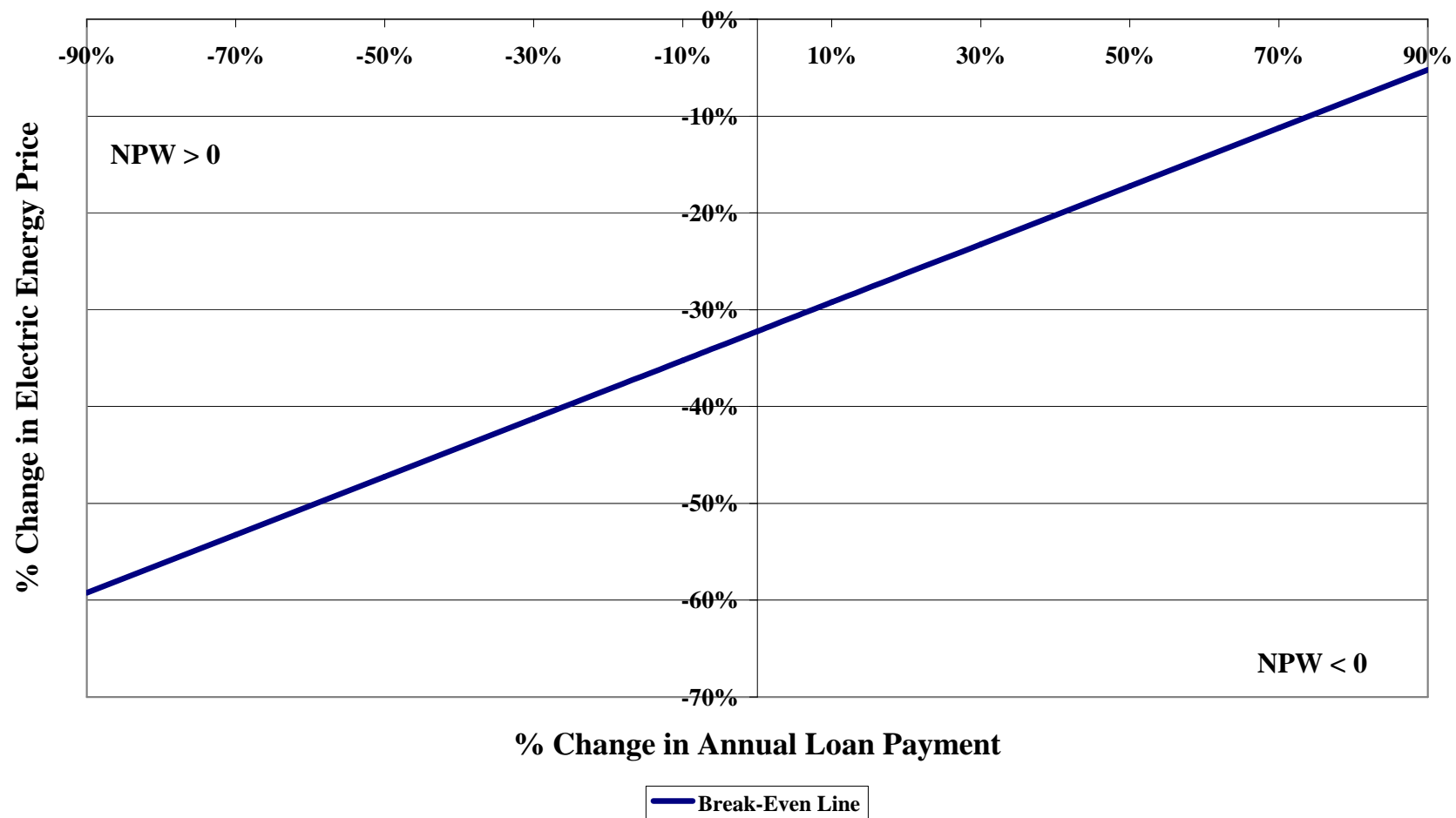


Figure 6.24: Case 2.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Annual Loan Payment.

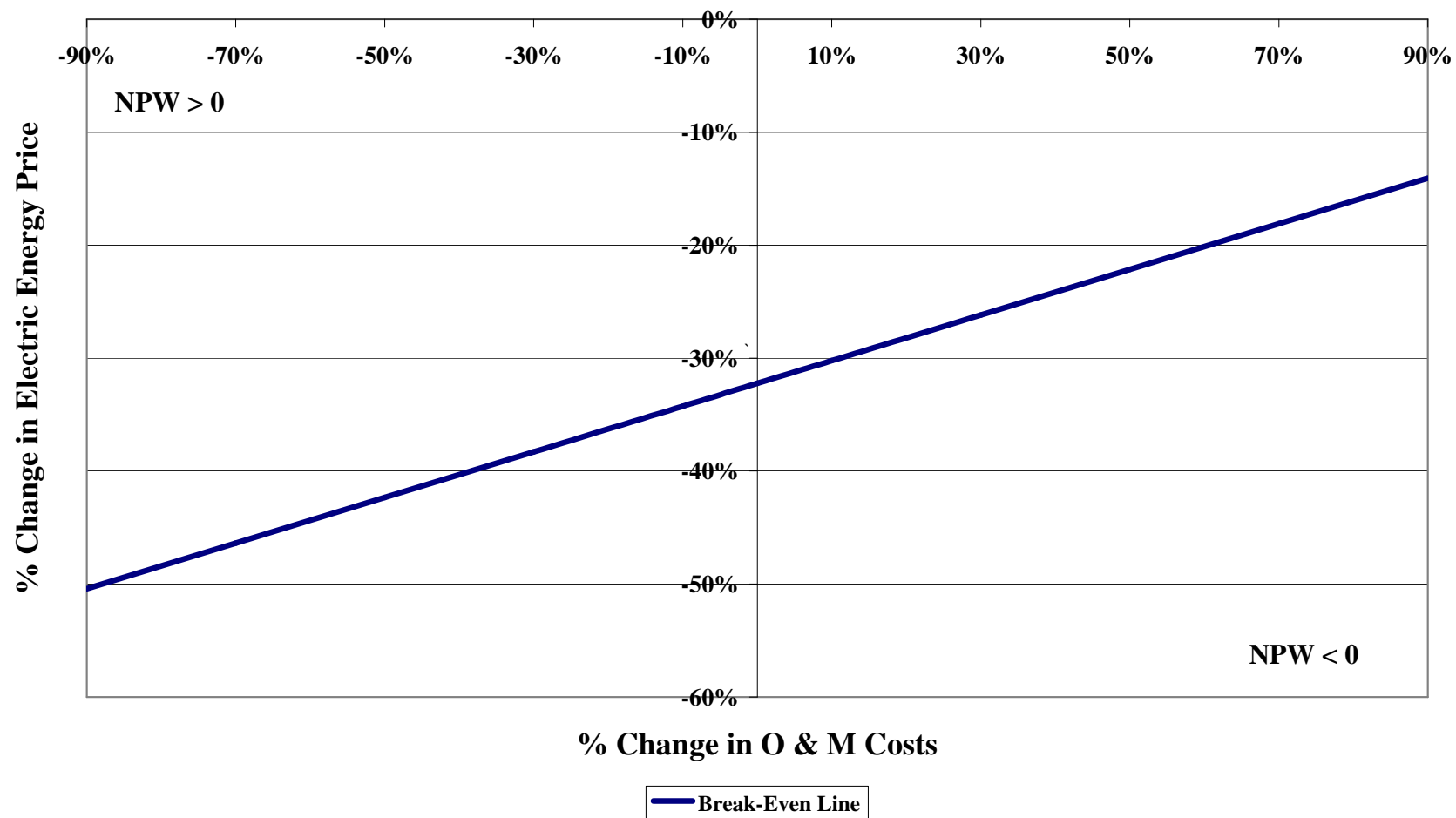


Figure 6.25: Case 2.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price. vs. O&M Cost.



Figure 6.26: Case 2.1 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Land Cost.

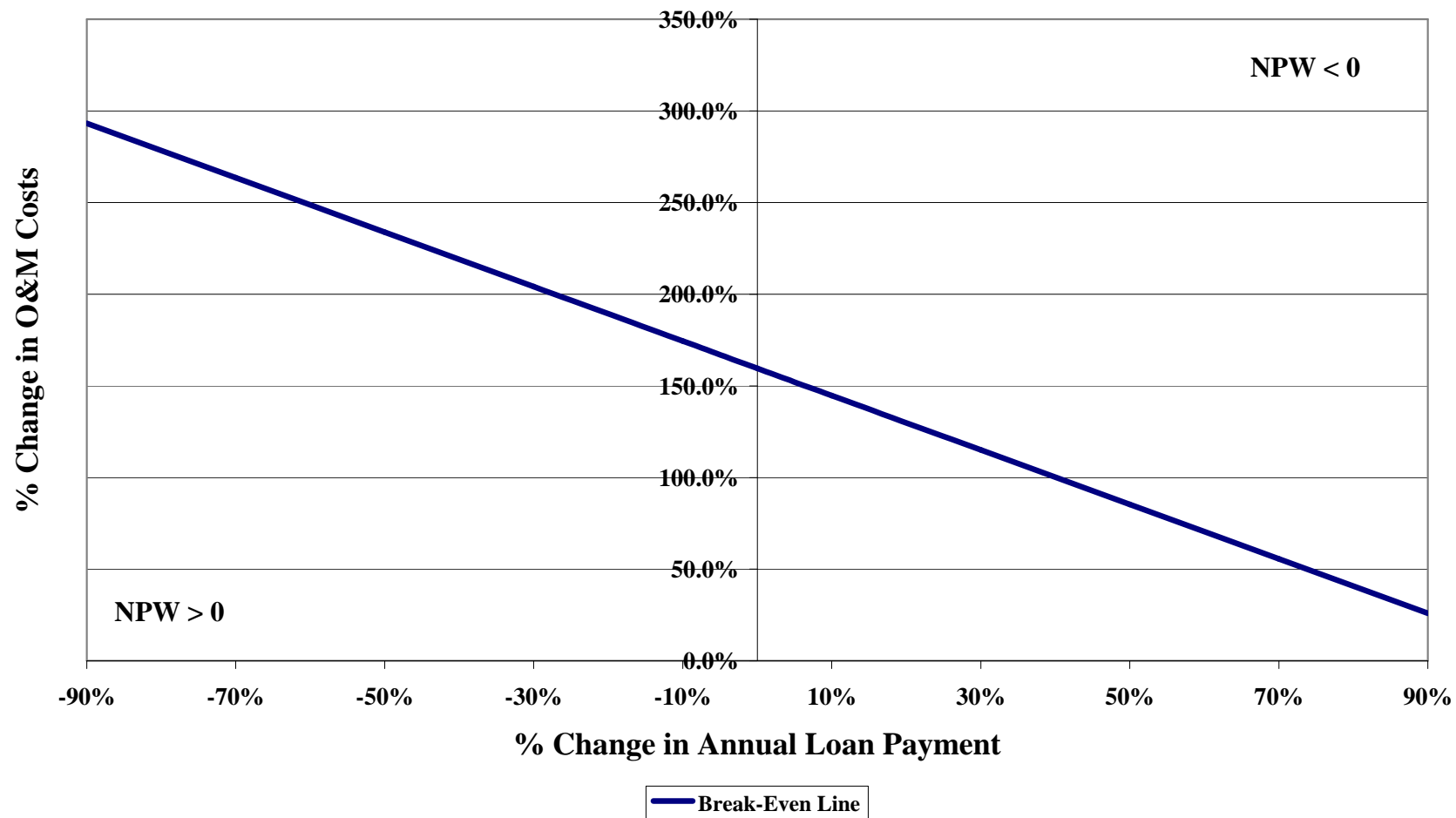


Figure 6.27: Case 2.1 Suzlon S64 Two-Parameter Sensitivity Curve: O&M Cost vs. Annual Loan Payment.

In the third case we present the before tax two-parameter sensitivity analysis for Case 2.3. Case 2.3 is one of the private utility cases, financed with an approximated 75% bond debt financing at 5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height. Figures 6.28 to 6.31 show the two-parameter sensitivity analysis results for Case 2.3.

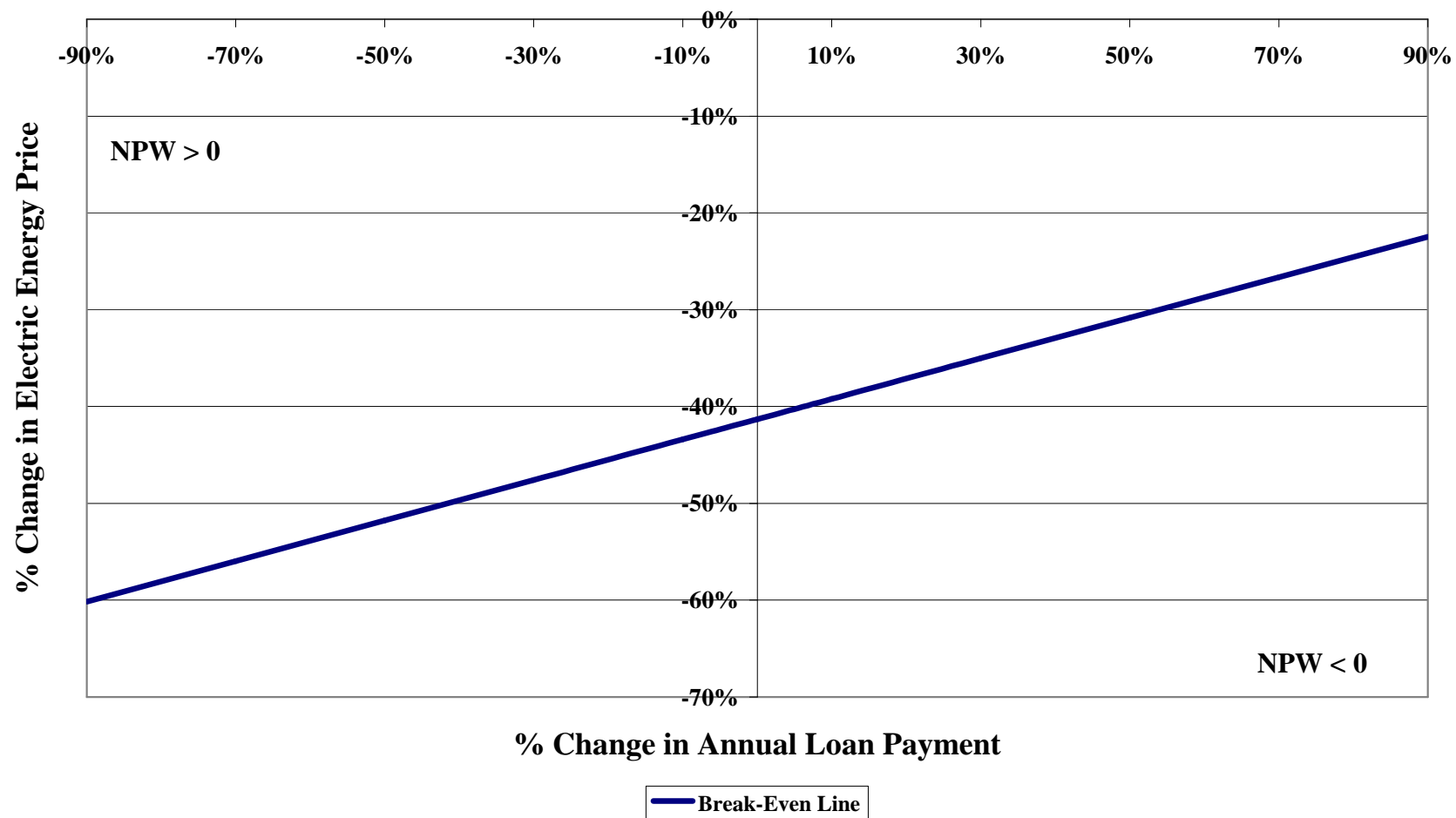


Figure 6.28: Case 2.3 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Annual Loan Payment.

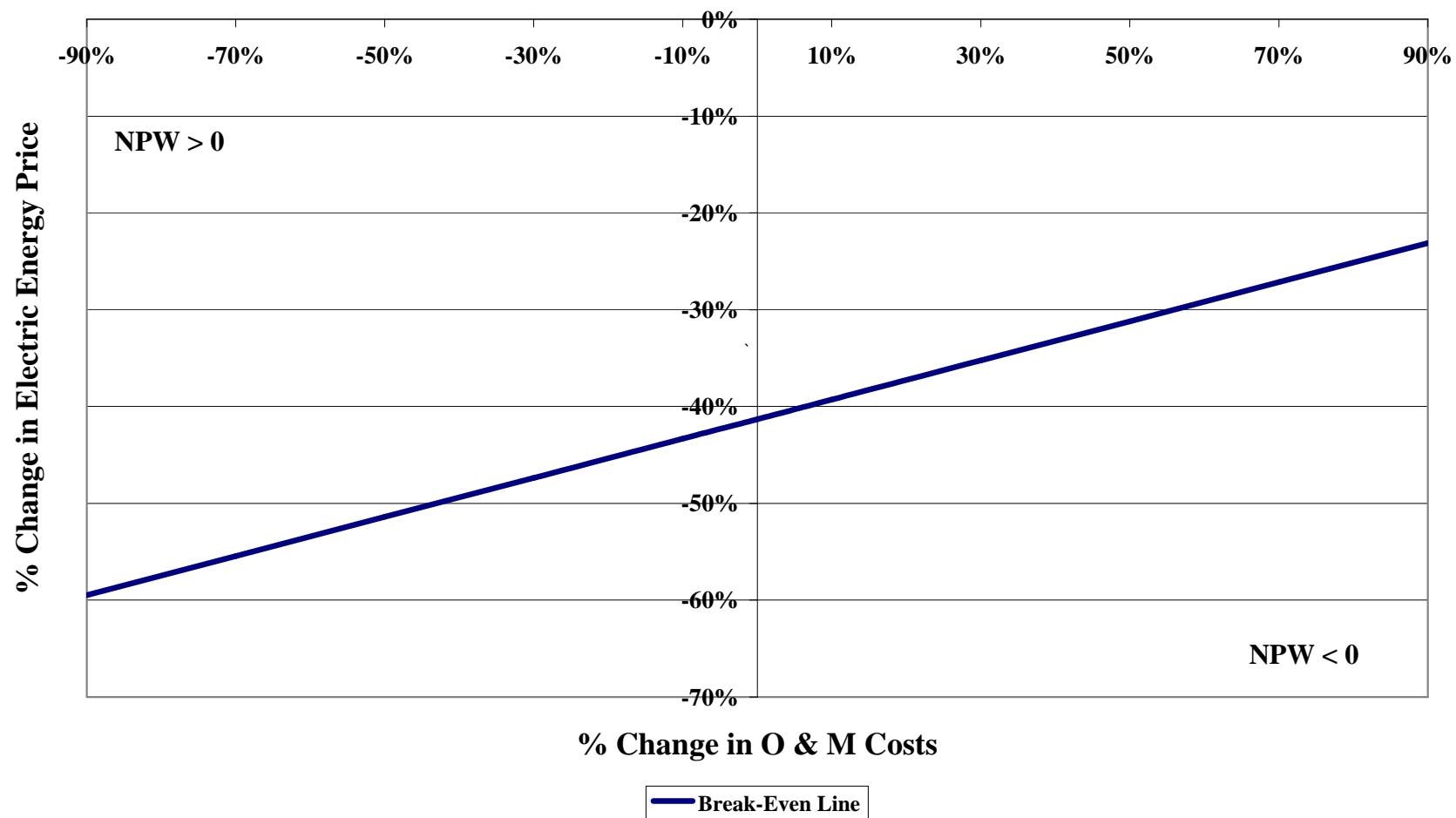


Figure 6.29: Case 2.3 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price. vs. O&M Cost.



Figure 6.30: Case 2.3 Suzlon S64 Two-Parameter Sensitivity Curve: Energy Price vs. Land Cost.

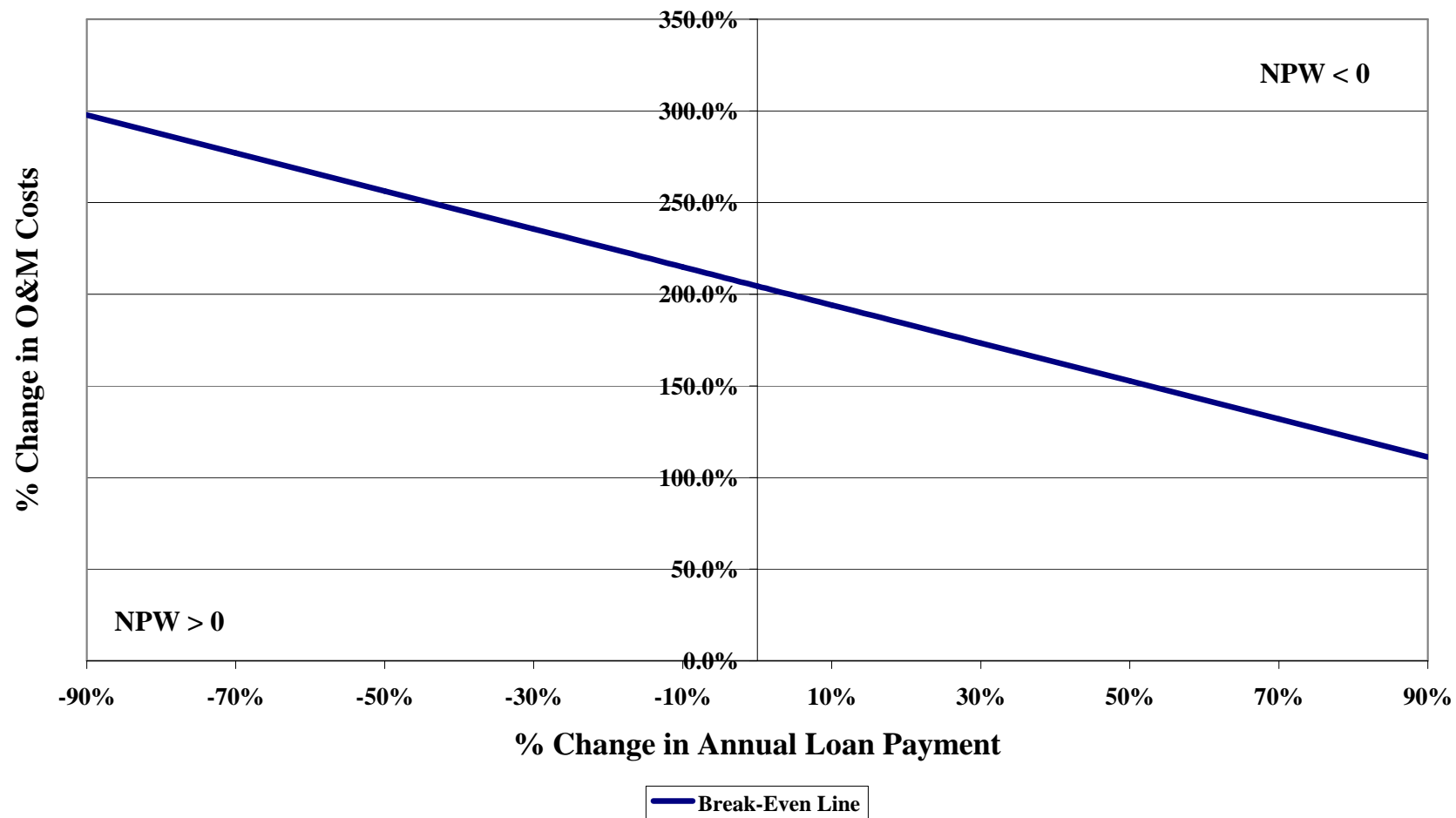


Figure 6.31: Case 2.3 Suzlon S64 Two-Parameter Sensitivity Curve: O&M Cost vs. Annual Loan Payment.

Analysis of Two Parameter Sensitivity Results

The two-parameter sensitivity analysis curves we have shown are for case 1.1, 2.1 and 2.3 before tax scenario using the Suzlon S64 turbine. The curves are a straight line in a plane that divides it in two regions: the area over the curve is the positive NPW region and the area under the curve is the negative NPW region, except for the curve of Annual Loan Payments vs. O&M Prices., where it is the opposite. The line that divides both regions is called the break even line, where any point laying over it gives NPW equal to zero. The curves show what combination of changes in two parameters give a positive or negative NPW.

For example in Case 1.1, Figure 6.20, if the energy price is reduced 30% and the annual loan payment is reduced 40%, that will be point (-40%,-30%) in the curve, the project will have a before tax positive NPW, but if the energy price is decreased 40%, point (-40%,-40%), the NPW will be negative.

6.4 Economic Monte Carlo Simulation Results

6.4.1 Introduction

Monte Carlo simulation was performed for the best turbine of Cases 1.1, 2.1 and 2.3. As stated before the best turbine for all the cases was the Suzlon S64 of 950 kW. The Monte Carlo simulation of this turbine was made at its suggested hub height.

For the Monte Carlo simulation we assigned probability distributions to the parameters that affect the economical analysis. The Monte Carlo simulation was

performed for a before taxes scenario. The parameters modeled for the Monte Carlo simulation are:

- The turbine installation cost. We did not have enough information to determine the real price of the installation cost, so we assumed that it will vary in estimated range of \$1,000/kW to \$1,800/kW with a more probable chance of being near \$1,400/kW. Modeled using a triangular distribution with a minimum of \$1,000/kW installed, a mode of \$1,400/kW installed, and a maximum of \$1,800/kW installed.
- The energy price. From information and data found in the literature we modeled the energy price using a normal distribution with a mean value of \$0.0807/kWh, and a standard deviation of \$0.0243/kWh.
- The operation and maintenance cost. There was no sufficient information to assign a specific probabilistic model to O&M costs, so we assumed a range where the real cost could be and modeled it using a uniform distribution with a minimum of \$0.01/kWh produced, and a maximum of \$0.02/kWh produced.
- The land cost. Using the same analysis as with the O&M cost we modeled the land cost using the uniform distribution with a minimum of \$2,000/turbine installed, and a maximum of \$5,000/turbine installed.

The objective of the Monte Carlo simulation is to assess the investor of the economical risk the project may present. We performed a 3,000 trial Monte Carlo simulation for each case. The measurements of risk we will present include the net present worth expected value (mean) and standard deviation, the coefficient of variation, the most

probable minimum and maximum net present worth results, and the percentage and number of negative net present worth results.

6.4.2 The Monte Carlo (MC) Simulation Results

In the first case we present the before tax Monte Carlo simulation for Case 1.1. Case 1.1 is one of the private investor cases, financed with 75% loan debt financing at 12% interest rate for 12 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height.

Table 6.27: Case 1.1 S64 Monte Carlo Simulation Results.

Measurement of Risk	Result
NPW Expected Value (Mean)	\$2,138,657.91
NPW Standard Deviation	\$5,821,451.01
Coefficient of Variation	2.7220
Minimum NPW	-\$17,507,136.75
Maximum NPW	\$23,118,710.74
Number of Negative NPW Results	1087
Percentage of Negative NPW Results	36.23%

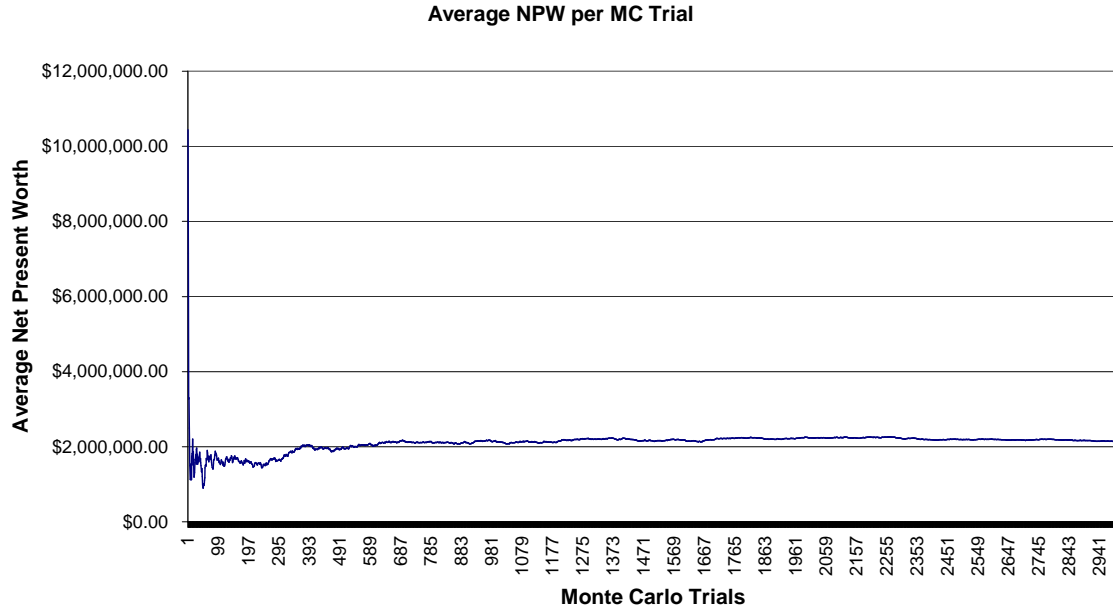


Figure 6.32: Case 1.1 S64 Expected NPW vs. MC Trials.

In the second case we present the before tax Monte Carlo simulation for Case 2.1. Case 2.1 is one of the private utility cases, financed with 75% loan debt financing at 7.5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height.

Table 6.28: Case 2.1 S64 Monte Carlo Simulation Results.

Measurement of Risk	Result
NPW Expected Value (Mean)	\$4,768,101.80
NPW Standard Deviation	\$5,763,295.01
Coefficient of Variation	1.2087
Minimum NPW	-\$49,845,429.88
Maximum NPW	\$24,023,411.34
Number of Negative NPW Results	607
Percentage of Negative NPW Results	20.23%

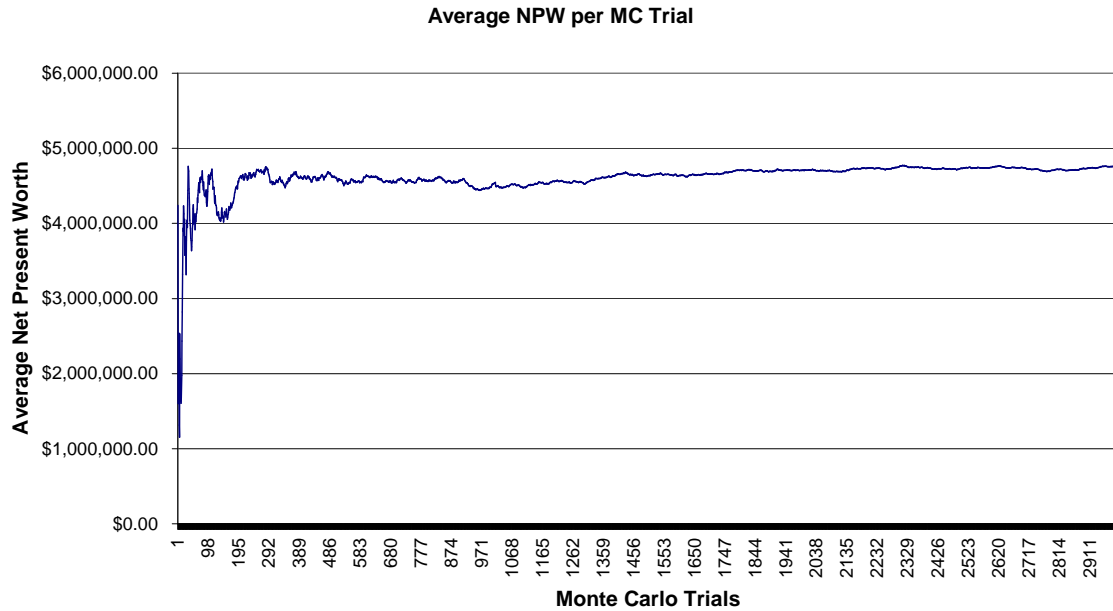


Figure 6.33: Case 2.1 S64 Expected NPW vs. MC Trials.

In the third case we present the before tax Monte Carlo simulation for Case 2.3. Case 2.3 is one of the private utility cases, financed with an approximated 75% bond debt financing at 5% interest rate for 20 years. The analysis is for the turbine Suzlon S64 950 kW at a 64 meter hub height.

Table 6.29: Case 2.3 S64 Monte Carlo Simulation Results.

Measurement of Risk	Result
NPW Expected Value (Mean)	\$6,819,920.67
NPW Standard Deviation	\$5,984,212.31
Coefficient of Variation	0.8775
Minimum NPW	-\$47,462,238.28
Maximum NPW	\$26,429,513.66
Number of Negative NPW Results	368
Percentage of Negative NPW Results	12.27%

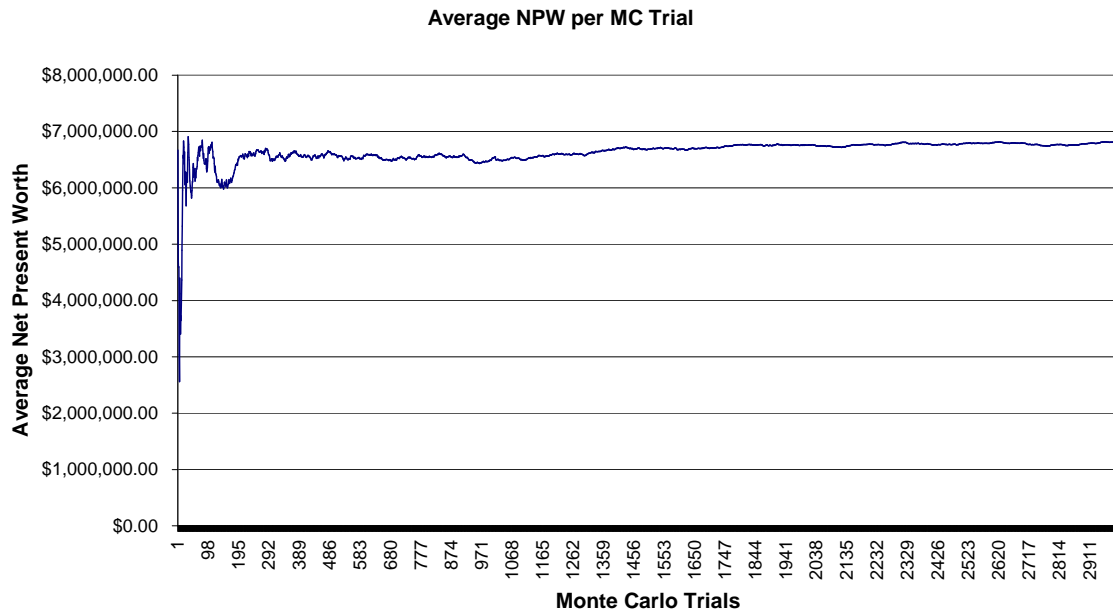


Figure 6.34: Case 2.3 S64 Expected NPW vs. MC Trials.

6.4.3 Analysis of The Monte Carlo (MC) Simulation Results

The Monte Carlo simulation results show the level of risk of each project developed using the Suzlon S64 wind turbine. The simulations were performed for a before tax scenario. For the three cases (1.2, 2.1 and 2.3) the maximum net present worth result is similar: a maximum average of \$25M.

Case 1.1 is the most risky of all with an expected value around \$2.14M, a coefficient of variation over 2, and a percentage of negative outcomes of 36.23%. Case 2.1 is much less risky than Case 1.1 with an expected value around \$4.77M, a coefficient of variation slightly higher than 1.00, and a percentage of negative outcomes of 20.23%. Case 2.3 is the least risky of all the cases with an expected value around \$6.82M, a coefficient of variation of less than 0.90, and a percentage of negative outcomes of 12.27%.

From the NPW results tabulated in Tables 6.22 and 6.23 it was expected that Case 2.3 will be the less risky since it has the higher NPW and the probability functions that describes the parameters of each case are the same. This situation causes a higher NPW less risk effect in the analysis.

An important observation is that the NPW expected mean values obtained from the probabilistic method (Monte Carlo Simulation) are better than the ones obtained using the deterministic NPW method. Table 6.30 presents a comparison of these results.

Table 6.30: Deterministic and Probabilistic Expected NPW Mean Values.

Case	Method	
	Deterministic – NPW Method	Probabilistic –Monte Carlo Simulation
Case 1.1	\$1,397,439.00	\$2,138,657.91
Case 2.1	\$3,825,886.32	\$4,768,101.80
Case 2.3	\$4,941,465.90	\$6,819,920.67

7 WIND FARM ARRAY AND SITTING RECOMMENDATIONS

7.1 Introduction

In this section we show two possible wind turbine arrays taking into consideration the engineering and technical aspect discussed in Chapter 5. The wind turbine arrays presented are made using the best three wind turbines from the net present worth analysis. Table 7.1 show the wind turbines, their rated power, the number of turbines needed for a 10 MW array, their hub height, their rotor diameter and their rotor sweep area.

Table 7.1: Relevant Wind Turbine Information for Wind Farm Array.

Turbine	Power (kW)	Turbines Needed for 10 MW Array	Hub Height (m)	Rotor Diameter (m)	Rotor Sweep Area (m²)
Suzlon S64	950	11	64	64	3218
DE Wind D6-1000	1000	10	68	62	3019
Gamesa G80	1800	6	78	80	5027

7.2 Wind Farm Arrays

Using as a reference the “Rule of Thumb” for wind turbine spacing in a wind farm, we designed two arrays where the turbines are an average of 4 rotor diameters apart in the direction perpendicular to the prevailing winds and an average of 7 rotor diameters in the direction parallel to the winds direction.

A 10 MW capacity array for a location in the east coast of Puerto Rico was designed. Since the rotor diameter for the Suzlon S64 and the DE Wind-1000 are similar the array for both turbines is the same. For this array a distance of 4 rotor diameters is equal to 256 meters, and a distance of 7 rotor diameters is equal to 448 meters.

In the array using Gamesa G80 turbines, the turbines are more sparse, but the array uses less turbines because the power capacity of the G80 is much bigger. In this array 4 rotor diameters is equal to 320 meters, and 7 rotor diameters is equal to 560 meters.

Figures 7.1 and 7.2 show the wind farm arrays using the turbines mentioned above.

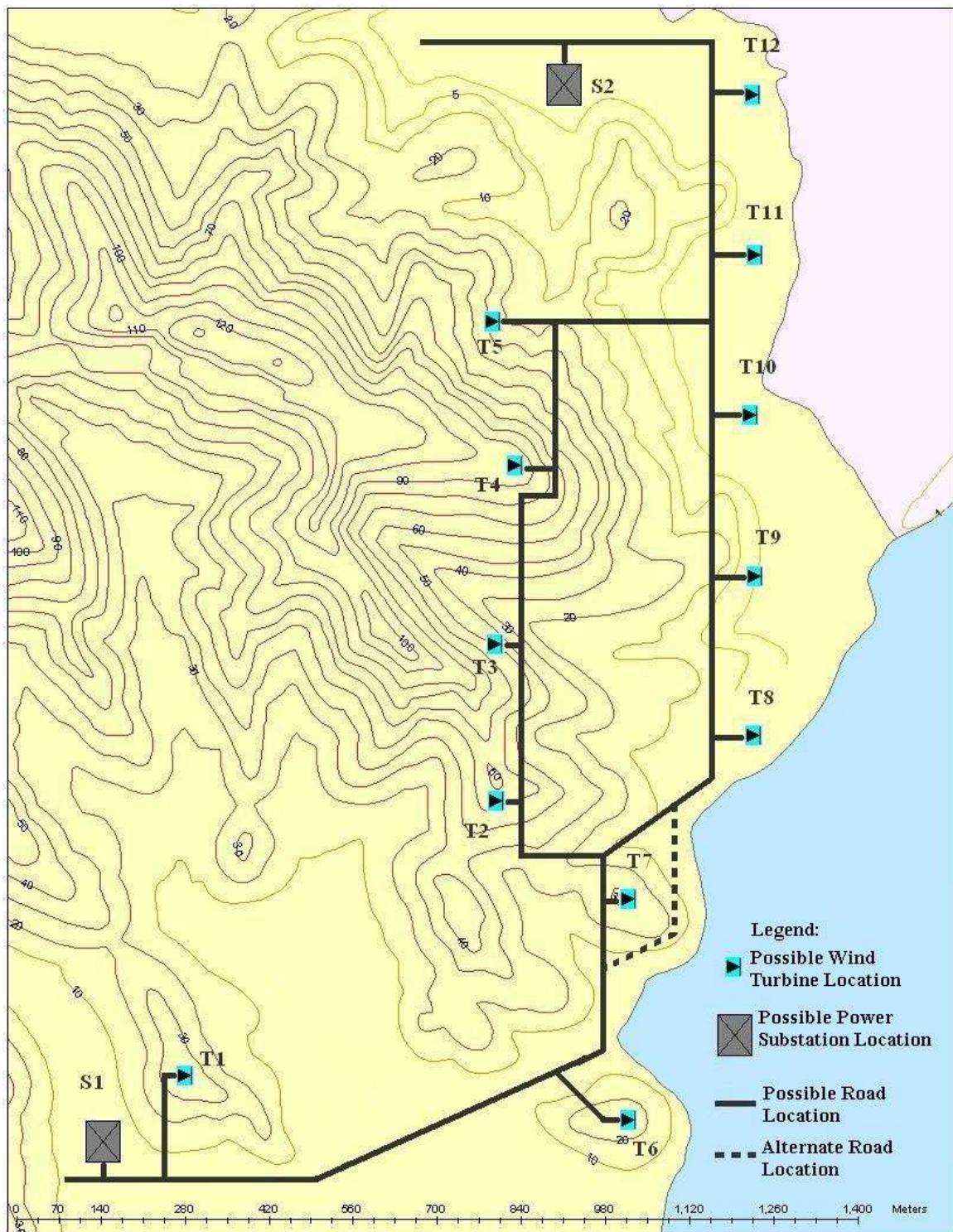


Figure 7.1: Possible Wind Farm Array #1 – Suzlon S64 and DE Wind D6-1000 Turbines.

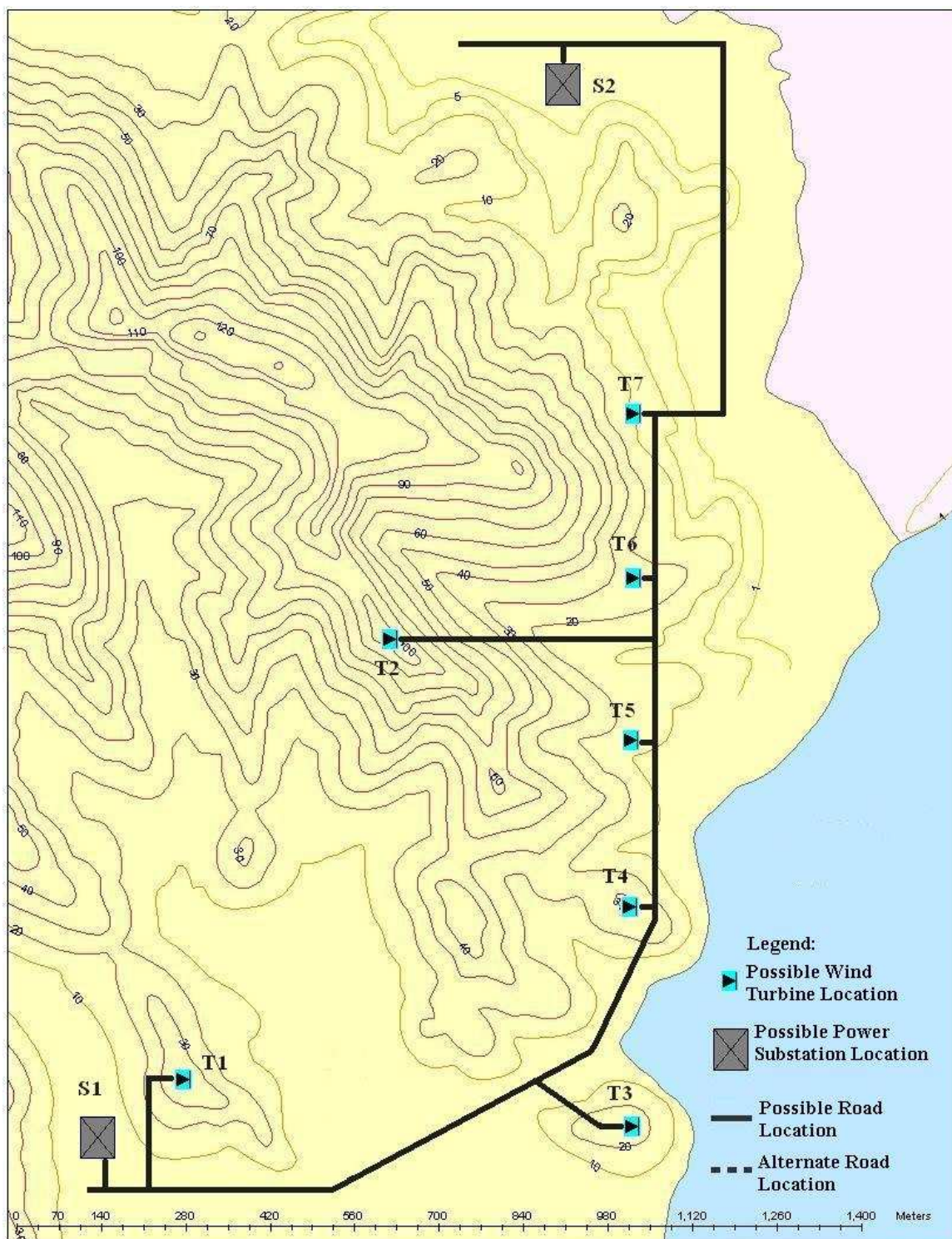


Figure 7.2: Possible Wind Farm Array #2 – Gamesa G80 Turbines.

As shown in array #1 a wind farm there are 12 possible locations for wind turbines with a rotor diameter of 64 meters or less. Of those 12 turbines a design using the Suzlon S64 will require only 11 turbines, and a design using the DE Wind D6-1000 will require only 10 turbines.

Array #2 shows 7 possible locations for wind turbines with a rotor diameter of 80 meters or less. A design using the Gamesa G80 will require only 6 turbines.

Also in array #1 and #2 there are two power substations. A 10 MW wind farm would only require one 10 MW substation. We show two possible locations: one at the entrance to the wind farm and one the other end. The location of the substation is relative to designer and wind farm owner point of view. One may prefer the substation located at the entrance of the wind farm because it is more accessible for maintenance, others would prefer it at the end of the wind farm so it is more protected for any vandalism.

In the design there are also two entrances to the wind farm; one at the north side and one at the south side. The selection of the entrance point will depend of any available roads near the farm that makes it easier for heavy equipment to enter the site.

7.3 Social and Environmental Impact of the Wind Farm Array

The site where the turbines are planned to be located have the advantage that the nearest community near the site is at least 500 meters from it. This means that there should not be any problems with the noise the wind turbines may generate. One concern is the visual impact the turbines may cause to the site. The site has a beautiful view to the

sea and developers may find more profitable to construct a beach resort before installing a wind farm in it.

Another important aspect to consider in this site are the birds. Since the location of the site is in the east coast. Most migratory arrive in the island from the east and the location of the wind farm may be in their possible path, although the probability of a high bird death rate should be low if we consider that the east coast of Puerto Rico has an approximated 35 mile coast line.

8 CONCLUSSIONS AND RECOMMENDATIONS

8.1 Conclusions

In our work we have analyzed wind data using the Weibull probability distribution and determined the energy production for a potential wind farm site in the east coast of Puerto Rico. An engineering economic model was developed based on the net present worth to analyze the economic viability of the wind farm project. This economic model uses the energy production for the site and other economic variables and determines the net present worth of the project. Finally we designed two possible wind farm arrays taking into consideration the physical properties of three different wind turbines. Our conclusions are:

- We developed an economic model based on the net present worth method that allows studying the economic feasibility of wind farm projects taking into consideration factors such as the income taxes and the effect of inflation. Our economic model permits us to perform uncertainty and risk analysis using sensitivity analysis and Monte Carlo Simulation.
- The multiple analyses realized using our economic model permits us to conclude that a wind farm project is a feasible one under the economic conditions we studied. The east coast of Puerto Rico seems to have adequate wind conditions to establish a wind farm.

- The economic analysis results show that a wind farm project is an attractive investment for utility companies due to their capital power and access to better financing terms.
- The fourth quarter (October, November and December) data showed the best wind speeds and energy production for the site. The first quarter (January, February and March) data showed the worst wind speeds and energy production for the site.
- Adjusting the CRC wind speed to a 50 meter height, the site wind power density is equal to 337 W/m^2 . This classifies the site as a class 3 with a fair resource potential based on the standard wind power classification, [NREL 2003].
- Wind turbine energy curves provide the advantage of creating an energy production vs. mean wind speed curve that considers the site wind probability density function and the turbine power curve characteristic. The energy curve has the advantage of showing the energy production for a range of arithmetic mean wind speed values making it easier to observe the effects of wind shear in the wind turbine.
- The net present worth results showed that for the given hub height conditions of the top three turbines analyzed a private investor and a utility company will obtain a profitable net present worth. These favorable results allow the private investor and the utility to lower the energy prices and be more competitive in the energy market.

- A private investor (case #1) could sell the energy as low as \$0.0837/kWh. If a PTC incentive is added, the investor could lower the energy price to \$0.0792/kWh. If the project were income tax free then the energy price will be \$0.0761/kWh.
- A utility company, like PREPA, could sell the energy as low as \$.0673/kWh if the project is financed with a loan. If the PTC incentive is added energy price will be lowered to \$0.0648/kWh. In a no income tax scenario the price will be \$0.0634/kWh. If the project is financed with bonds the energy price could be lowered to \$0.0554/kWh. If the PTC incentive is added the price will be \$0.0549/kWh. If the project were income tax free the price will be \$0.0544/kWh.
- Based on our NPW and IRR results the PTC incentive is preferred over the 5-year MACRS incentive when the projects IRR is near the project MARR. When IRR is much higher than the project MARR then the 5-year MACRS is preferred.
- Increasing the capacity of the wind farm takes advantage of the economies of scale which results in a better economic result. This is shown by the installed capacity sensitivity curve.
- The sensitivity analysis showed that a wind farm project is very sensitive to: energy prices, energy production and the wind farm installation costs.
- The risk analysis using Monte Carlo simulation showed that utility company has less economic risk in this type of project. The private investor has more risk, which may impede the investor to commit to the project.

- Comparing the deterministic net present worth value with the probabilistic expected net present worth value, the wind farm project may yield a better outcome than was deterministically estimated.
- The Suzlon S64 was found to be the best turbine for this site. The Suzlon S64 is also capable of sustaining 152 mph winds which makes it a turbine with a high survival wind speed and capable of surviving at most a class 4 hurricane.

8.2 Recommendations for Future Work

The following are recommendations for future work:

- The economic model was implemented using Excel. MATLAB could be used to consider after tax two-parameter sensitivity analysis and after tax Monte Carlo simulation. Also the wind data analysis could be linked to the economic model so the complete wind farm assessment can be made in only one program.
- Expand the economic model to consider the costs incurred during the wind speed measurement stages and the preconstruction phases that include the permitting process. This economic model would contain the variables that affect the wind farm installation costs. This is of importance because this type of project is very capital intensive.
- The economic model does not consider intangibles such as environmental factors. The model could be modified to quantify the advantages of wind generated electricity compared to conventional fossil fuel generation. It is

known that wind generation does not emit pollutants to the air and water as the fossil fuel generation facilities normally do.

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Appendix A. Wind Data Analysis Results

In this appendix we present the wind speed data analysis results for the months of February, March, April, May, July, August, November and December. The measurements were taken in the year 1987 in Fajardo, Puerto Rico. The site of the measurements is located very near the coast in an area that is known as the Cape of San Juan.

Data of the months of January, June, September and October is missing due to failures in the measurement equipment and lack of visual inspection during the measurement stage.

Data analysis results for the month of February, 1987:

Table A.1: Parameter Estimation for February, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	3.34	3.71	2.43	3.36
Scale Factor (η , c)	6.87	6.92	7.26	6.89

Table A.2: Average Wind Speed February, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.15	6.25	6.44	6.19
Cubic Root Cube Mean Speed	6.76	6.76	7.54	6.79

Table A.3: Energy Production for February, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
127.07	95.66	127.07
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		126.71

Table A.4: Power Production for February, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
191.53	142.35	189.09

Data analysis results for the month of March, 1987:

Table A.5: Parameter Estimation for March, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	2.78	3.13	2.22	2.86
Scale Factor (η , c)	6.76	6.76	7.06	6.80

Table A.6: Average Wind Speed for March, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.02	6.04	6.25	6.06
Cubic Root Cube Mean Speed	6.84	6.71	7.50	6.84

Table A.7: Energy Production for March, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
145.97	99.46	145.97
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		145.39

Table A.8: Power Production for March, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic root Cube Mean Wind Speed (W/m^2)
195.85	133.69	196.20

Data analysis results for the month of April, 1987:

Table A.9: Parameter Estimation for April, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β, k)	2.94	3.23	2.52	2.96
Scale Factor (η, c)	7.16	7.17	7.33	7.17

Table A.10: Average Wind Speed for April, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	6.37	6.42	6.51	6.40
Cubic Root Cube Mean Speed	7.16	7.09	7.56	7.17

Table A.11: Energy Production for April, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
161.94	114.23	161.94
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		161.51

Table A.12: Power Production for April, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
226.24	158.65	224.92

Data analysis results for the month of May, 1987:

Table A.13: Parameter Estimation for May, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	2.55	2.83	2.10	2.60
Scale Factor (η , c)	6.58	6.65	6.81	6.61

Table A.14: Average Wind Speed for May, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	5.83	5.93	6.03	5.87
Cubic Root Cube Mean Speed	6.74	6.70	7.36	6.75

Table A.15: Energy Production for May, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
139.55	90.07	139.55
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		138.84

Table A.16: Power Production for May, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
188.26	121.06	187.56

Data analysis results for the month of July, 1987:

Table A.17: Parameter Estimation for July, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	4.37	4.98	4.67	4.61
Scale Factor (η , c)	7.73	7.71	7.71	7.95

Table A.18: Average Wind Speed for July, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	7.04	7.07	7.05	7.05
Cubic Root Cube Mean Speed	7.48	7.43	7.44	7.47

Table A.19: Energy Production for July, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
190.64	159.02	190.64
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		190.52

Table A.20: Power Production for July, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
255.44	213.74	256.24

Data analysis results for the month of August, 1987:

Table A.21: Parameter Estimation for August, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	2.50	2.74	2.23	2.52
Scale Factor (η , c)	6.49	6.49	6.59	6.51

Table A.22: Average Wind Speed for August, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	5.74	5.78	5.83	5.77
Cubic Root Cube Mean Speed	6.67	6.57	7.00	6.68

Table A.23: Energy Production for August, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
135.50	86.29	135.50
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		134.76

Table A.24: Power Production for August, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
182.64	115.98	182.12

Data analysis results for the month of November, 1987:

Table A.25: Parameter Estimation for November, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	2.43	2.69	1.98	2.48
Scale Factor (η , c)	8.56	8.66	8.84	8.61

Table A.26: Average Wind Speed for November, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	7.50	7.70	7.84	7.63
Cubic Root Cube Mean Speed	8.77	8.77	9.76	8.85

Table A.27: Energy Production for November, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
297.17	186.16	297.17
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		296.77

Table A.28: Power Production for November, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
424.50	258.56	412.74

Data analysis results for the month of December, 1987:

Table A.29: Parameter Estimation for December, 1987.

Weibull Parameters	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Shape Factor (β , k)	2.53	2.71	2.20	2.57
Scale Factor (η , c)	7.94	7.93	8.15	7.97

Table A.30: Average Wind Speed for December, 1987.

Average Wind Speed (m/s)	Parameter Estimation Method			
	Maximum Likelihood Estimators	Justus' Approximation	Least Squares Method	"Quick" Method
Arithmetic Mean Speed	7.03	7.05	7.22	7.07
Cubic Root Cube Mean Speed	8.15	8.05	8.69	8.17

Table A.31: Energy Production for November, 1987.

Energy Production Parameter		
Energy Probability Function (kWh/m^2)	Arithmetic Mean Wind Speed (kWh/m^2)	Cubic Root Cube Mean Wind Speed (kWh/m^2)
246.90	158.44	246.90
Maximum Energy Wind Turbine can Capture in the 3 to 25 m/s range (kWh/m^2)		246.45

Table A.32: Power Production for November, 1987.

Power Production Parameter		
Wind Power Density (W/m^2)	Arithmetic Mean Wind Speed (W/m^2)	Cubic Root Cube Mean Wind Speed (W/m^2)
334.02	212.96	331.86

Appendix B. Economic Analysis Results

In this appendix we show the economic analysis results of the other four wind turbines. The analysis was performed considering that the power captured by the turbines is much less at the height (25 m) the wind speed measurements were taken compared with the turbine manufacturer recommended turbine hub height. Tables C.1 to C.4 show the Case #1 economic analysis results and Tables C.5 to C.8 show the Case #2 economic analysis results for the four wind turbines. The results show the project net present worth (NPW), internal rate of return (IRR) and simple payback period.

Table B.1: DE Wind D6 1250 kW Case #1 Economic Results.

Turbine: DE Wind D6 1250 kW		
Hub Height	25 m	68 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$3,164,694.82	\$811,887.30
IRR	6.877%	17.432%
Payback Period	17 years	8 years
<i>After Taxes Results:</i>		
NPW	-\$3,614,536.54	-\$471,885.02
IRR	4.666%	13.419%
Payback Period	18 years	13 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$2,504,077.36	\$1,748,612.90
IRR	8.909%	19.930%
Payback Period	15.5 years	6.5 years
<i>After Taxes Results</i>		
NPW	-\$3,117,036.66	\$148,293.26
IRR	6.453%	15.471%
Payback Period	16 years	11.5 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$3,485,711.81	-\$746,309.65
IRR	3.353%	12.107%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$3,014,758.19	\$759,050.95
IRR	6.730%	17.514%
Payback Period	16.5 years	7 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$3,407,223.25	-\$225,743.96
IRR	3.621%	14.091%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$3,672,705.23	-\$122,984.09
IRR	4.498%	14.571%
Payback Period	19 years	12.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$3,884,914.14	-\$884,323.73
IRR	1.455%	11.234%

Table B.2: Gamesa G52 850 kW Case #1 Economic Results.

Turbine: Gamesa G52 850 kW		
Hub Height	25 m	65 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$3,311,010.21	\$394,441.31
IRR	6.685%	16.138%
Payback Period	17 years	10 years
<i>After Taxes Results:</i>		
NPW	-\$3,759,414.34	-\$783,984.57
IRR	4.493%	12.459%
Payback Period	18 years	13 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$2,643,256.06	\$1,319,478.05
IRR	8.709%	18.586%
Payback Period	15.5 years	8 years
<i>After Taxes Results</i>		
NPW	-\$3,254,757.76	-\$168,949.28
IRR	6.275%	14.481%
Payback Period	16.5 years	12 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$3,618,764.57	-\$1,026,940.67
IRR	3.179%	11.146%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$3,155,181.46	\$373,120.14
IRR	6.538%	16.186%
Payback Period	16.5 years	8 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$3,542,467.59	-\$568,499.50
IRR	3.435%	12.802%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$3,821,539.70	-\$509,597.58
IRR	4.317%	13.298%
Payback Period	19.5 years	13 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$4,025,950.95	-\$1,226,389.09
IRR	1.278%	9.998%

Table B.3: Gamesa G83 2 MW Case #1 Economic Results.

Turbine: Gamesa G83 2 MW		
Hub Height	25 m	78 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$2,857,417.16	\$1,567,283.58
IRR	7.596%	19.851%
Payback Period	16 years	6.5 years
<i>After Taxes Results:</i>		
NPW	-\$3,344,475.31	\$36,237.21
IRR	5.317%	15.124%
Payback Period	17 years	11.5 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$2,175,221.22	\$2,556,702.13
IRR	9.660%	22.431%
Payback Period	15 years	5.5 years
<i>After Taxes Results</i>		
NPW	-\$2,837,212.20	\$679,359.27
IRR	7.126%	17.196%
Payback Period	16 years	7.5 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$3,249,508.25	-\$308,315.94
IRR	4.006%	13.783%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$2,716,419.94	\$1,447,928.77
IRR	7.456%	19.978%
Payback Period	15.5 years	5.5 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$3,156,402.41	\$355,473.23
IRR	4.326%	16.483%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$3,392,880.77	\$546,402.40
IRR	5.177%	16.991%
Payback Period	18 years	5.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$3,648,710.59	-\$318,740.43
IRR	2.114%	13.584%

Table B.4: Vestas V66 1.75 MW Case #1 Economic Results.

Turbine: Vestas V66 1.75 MW		
Hub Height	25 m	78 m
CASE 1.1		
<i>Before Taxes Results:</i>		
NPW	-\$4,779,205.08	-\$373,332.85
IRR	3.763%	13.987%
Payback Period	20 years	12.5 years
<i>After Taxes Results:</i>		
NPW	-\$5,091,458.16	-\$1,376,596.41
IRR	1.851%	10.786%
Payback Period	22 years	14 years
CASE 1.2		
<i>Before Taxes Results</i>		
NPW	-\$4,186,476.62	\$525,310.89
IRR	5.657%	16.345%
Payback Period	18 years	10.5 years
<i>After Taxes Results</i>		
NPW	-\$4,626,146.94	-\$766,211.91
IRR	3.523%	12.769%
Payback Period	20 years	13 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$4,803,051.88	-\$1,551,243.78
IRR	0.507%	9.484%
CASE 1.3		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$4,591,874.88	-\$344,995.02
IRR	3.609%	13.974%
Payback Period	19.5 years	12 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$4,777,286.01	-\$1,200,890.02
IRR	0.591%	10.655%
CASE 1.4		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$5,183,734.70	-\$1,215,892.48
IRR	1.580%	11.217%
Payback Period	23 years	14 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$5,201,227.53	-\$1,847,471.04
IRR	-1.378%	7.978%

Table B.5: DE Wind D6 1250 kW Case #2 Economic Results.

Turbine: DE Wind D6 1250 kW		
Hub Height	25 m	68 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	-\$423,188.04	\$3,553,394.08
IRR	13.098%	31.335%
Payback Period	8 years	3 years
<i>After Taxes Results:</i>		
NPW	-\$846,095.10	\$1,869,102.66
IRR	10.662%	24.365%
Payback Period	8 years	4 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$237,429.42	\$4,490,119.68
IRR	15.962%	33.792%
Payback Period	7 years	3 years
<i>After Taxes Results</i>		
NPW	-\$383,627.48	\$2,477,974.30
IRR	13.210%	26.380%
Payback Period	7 years	3.5 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$934,331.49	\$1,433,771.77
IRR	9.912%	22.699%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$2,455,431.35	\$6,708,121.61
IRR	30.229%	51.981%
Payback Period	3.5 years	2 years
<i>After Taxes Results</i>		
NPW	\$1,864,421.38	\$4,654,182.04
IRR	27.792%	42.606%
Payback Period	3.5 years	2 years
<i>After Taxes + Inflation Results</i>		
NPW	\$1,210,138.35	\$3,511,650.38
IRR	24.070%	38.452%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$141,260.42	\$3,432,131.13
IRR	14.336%	31.474%
Payback Period	6.5 years	3 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$730,020.45	\$2,270,951.28
IRR	11.006%	27.645%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$848,236.79	\$2,676,692.03
IRR	10.454%	29.887%
Payback Period	7.5 years	3 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$1,247,592.27	\$1,732,234.96
IRR	7.237%	26.103%

Table B.6: Gamesa G52 850 kW Case #2 Economic Results.

Turbine: Gamesa G52 850 kW		
Hub Height	25 m	65 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	-\$514,673.29	\$3,190,778.22
IRR	12.732%	29.374%
Payback Period	8 years	3 years
<i>After Taxes Results:</i>		
NPW	-\$928,092.03	\$1,624,590.28
IRR	10.335%	23.013%
Payback Period	8.5 years	4 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$153,080.86	\$4,115,814.97
IRR	15.608%	31.858%
Payback Period	7 years	3 years
<i>After Taxes Results</i>		
NPW	-\$458,356.08	\$2,225,864.16
IRR	12.902%	25.051%
Payback Period	7.5 years	4 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$1,008,803.50	\$1,214,216.95
IRR	9.014%	21.409%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$2,290,021.01	\$6,252,755.11
IRR	28.078%	46.797%
Payback Period	3.5 years	2 years
<i>After Taxes Results</i>		
NPW	\$1,690,580.49	\$4,292,638.51
IRR	25.710%	38.592%
Payback Period	3.5 years	2.5 years
<i>After Taxes + Inflation Results</i>		
NPW	\$1,018,538.80	\$3,165,485.53
IRR	22.049%	34.555%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$225,506.64	\$3,144,968.52
IRR	13.961%	29.809%
Payback Period	6.5 years	3 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$812,682.76	\$2,019,087.59
IRR	10.642%	26.028%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$938,520.70	\$2,346,072.06
IRR	10.072%	27.788%
Payback Period	8 years	3 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$1,334,156.42	\$1,442,500.77
IRR	6.866%	24.066%

Table B.7: Gamesa G83 2 MW Case #2 Economic Results.

Turbine: Gamesa G83 2 MW		
Hub Height	25 m	78 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	-\$115,910.38	\$4,308,790.36
IRR	14.478%	34.827%
Payback Period	7 years	3 years
<i>After Taxes Results:</i>		
NPW	-\$610,041.36	\$2,360,110.24
IRR	11.869%	26.750%
Payback Period	7 years	3.5 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	\$566,285.56	\$5,298,208.91
IRR	17.301%	37.243%
Payback Period	6.5 years	3 years
<i>After Taxes Results</i>		
NPW	-\$138,629.74	\$3,003,232.30
IRR	14.352%	28.730%
Payback Period	6.5 years	3.5 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$729,690.83	\$1,866,290.87
IRR	11.022%	24.980%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$2,784,287.49	\$7,516,210.83
IRR	31.970%	56.023%
Payback Period	3.5 years	2 years
<i>After Taxes Results</i>		
NPW	\$2,093,181.63	\$5,179,440.04
IRR	29.109%	45.263%
Payback Period	3.5 years	2 years
<i>After Taxes + Inflation Results</i>		
NPW	\$1,400,096.48	\$3,944,169.48
IRR	25.349%	41.032%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	\$158,396.60	\$4,043,246.16
IRR	15.747%	34.377%
Payback Period	6 years	3 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$478,218.32	\$2,781,001.27
IRR	12.376%	30.464%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$576,072.39	\$3,341,864.93
IRR	11.896%	33.592%
Payback Period	6 years	2.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$1,017,803.89	\$2,294,183.59
IRR	8.637%	29.701%

Table B.8: Vestas V66 1.75 MW Case #2 Economic Results.

Turbine: Vestas V66 1.75 MW		
Hub Height	25 m	78 m
CASE 2.1		
<i>Before Taxes Results:</i>		
NPW	-\$1,900,622.96	\$2,505,249.27
IRR	7.005%	25.929%
Payback Period	17 years	4 years
<i>After Taxes Results:</i>		
NPW	-\$2,074,884.96	\$1,165,778.36
IRR	5.006%	20.622%
Payback Period	20.5 years	4.5 years
CASE 2.2		
<i>Before Taxes Results</i>		
NPW	-\$1,307,894.50	\$3,403,893.01
IRR	10.040%	28.472%
Payback Period	12 years	3.5 years
<i>After Taxes Results</i>		
NPW	-\$1,623,687.24	\$1,749,896.79
IRR	7.876%	22.709%
Payback Period	12 years	4 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$2,004,041.54	\$803,300.62
IRR	4.733%	19.135%
CASE 2.3		
<i>Before Taxes Results</i>		
NPW	\$707,452.99	\$5,419,240.49
IRR	18.993%	39.797%
Payback Period	5 years	2.5 years
<i>After Taxes Results</i>		
NPW	\$422,633.24	\$3,652,521.04
IRR	17.666%	33.198%
Payback Period	5 years	3 years
<i>After Taxes + Inflation Results</i>		
NPW	-\$112,628.34	\$2,564,654.15
IRR	14.239%	29.319%
CASE 2.4		
<i>After Taxes + PTC Incentive Results</i>		
NPW	-\$1,580,270.58	\$2,565,024.54
IRR	8.080%	26.716%
Payback Period	11.5 years	3.5 years
<i>After Taxes + PTC Incentive + Inflation Results</i>		
NPW	-\$1,970,366.44	\$1,514,196.99
IRR	4.932%	23.026%
CASE 2.5		
<i>After Taxes + 5-Year MACRS Incentive Results</i>		
NPW	-\$2,204,920.03	\$1,723,767.45
IRR	4.146%	24.096%
Payback Period	21.5 years	3.5 years
<i>After Taxes + 5-Year MACRS Incentive + Inflation Results</i>		
NPW	-\$2,421,049.42	\$899,915.59
IRR	1.113%	20.481%

Appendix C. The Spreadsheet as a Tool for Economic Analysis

The use of spreadsheets is an efficient form of performing economic analysis where there is uncertainty and risk. The software MS Excel permits the development of such spreadsheets. The advantage of using spreadsheets is that it allows the quick analysis of different scenarios and thus facilitating sensitivity analysis. This permits to obtain different outputs and perform single-parameter sensitivity analysis in just seconds.

In this work the wind farm economic analysis was implemented using spreadsheets in Excel. This appendix describe in detail the spreadsheet variables that are requested as an input from the user. We also show pictures of the spreadsheet and cash flow diagrams for Cases 1.1 and 1.2. using the Suzlon S64 wind turbine.

In the following list all the user input variables for the spreadsheet are numbered and brief description of them is made:

1. Manufacturer. The name of the company that manufactures the wind turbine.
2. Model. The name or model given by the manufacturing company that identifies the wind turbine.
3. Rated power. Expected output power, in kW, of the wind turbine at a nominal wind speed given by the manufacturer.
4. Average wind speed. The arithmetic mean wind speed, in m/s, in the site where the wind turbines will operate.
5. Capacity to be installed. The total power capacity, in kW, that will be installed.

6. Turbine Availability factor. The percentage of time in a year that the wind farm will be operating. Modern wind farms have availability factors of 98% and higher, meaning only two percent of energy is loss due to maintenance and down time of the wind turbines.
7. Turbine Performance derating factor. A percentage value that represents degradation in the expected energy output of the wind turbines due to unexpected wind variations and turbulence.
8. Turbine Wear and Tear Derating Factor. This percentage value compensates for an output decrease due to the effects of operating life in the turbine performance.
9. Average power production based on the turbine energy curve. The average output power, in kW, of the wind turbine based the site and turbine energy curve and the operating mean wind speed.
10. Project life. The number of years that the wind farm is expected to operate.
11. Turbines System installed cost. The total cost of installing the wind farm in \$/kW installed. It includes the turbine costs, installation costs, transportation costs, utilities and overhead costs.
12. Wind Farm Operation and Management fixed cost. An operation and management cost that will always be the same regardless of the wind farm energy production.
13. Operation and Management variable cost. An operation and management cost, in \$/kWh, that will vary in proportion to the wind farm energy production.

14. Operation and Management variable escalation (inflation) rate. Year to year percentage value at which the operation and management cost is expected to increase.
15. Land Rights Option #1. Fixed amount of money, in \$/turbine installed, that is paid to the owner of the land where the turbines are sited.
16. Land Rights Option #2. Percentage values of the gross revenue that is paid to the owner of the land where the turbines are sited.
17. Average sale price of electricity (electrical energy). Average price at which the energy produced is expected to be sold.
18. Average sale price of electricity (electrical energy) escalation (inflation) rate. Year to year percentage value at which the energy produced price is expected to increase.
19. Loan #1 borrowed funds percentage. The percentage value of the wind farm total installed cost that is borrowed from lender number one.
20. Loan #1 interest rate. Is the charge to the borrower for the use of lender number one money.
21. Loan #1 debt term. Equal annual periods at which the repayment of the principal borrowed and the interest for loan number one will be paid. Also known as loan life.
22. Loan #2 borrowed funds percentage. The percentage value of the wind farm total installed cost that is borrowed from lender number two.
23. Loan #2 interest rate. Is the charge to the borrower for the use of lender number two money.

24. Loan #2 debt term. Equal annual periods at which the repayment of the principal borrowed and the interest for loan number two will be paid. Also known as loan life.
25. Bond face value. This is the value, in \$, the bond will repay the buyer when it reaches its maturity date.
26. Bond (coupon) annual rate. The interest paid annually on the face value of the bond.
27. Bond market price. Price at which the bond is sale. If the market price is higher than the bond face value the bond is called a premium bond. If the market price is lower than the bond face value the bond is called a discount bond.
28. Bond maturity time. The time that has to pass on which the face value is to be repaid.
29. Flotation cost. Costs associated with the issue of a bond. It includes investment bankers' fess, lawyers' fees, accountants' costs, and printing and engraving.
30. Income tax rate. Is the percent or rate of the taxable income that should be paid in taxes.
31. Tax exemptions. Tax deduction or deduction in the taxable income given to the investor of the project.
32. Minimum attractive rate of return (MARR). The minimum rate of return the wind farm investor is willing to obtain from the investment.

33. MACRS Depreciation. Modified Accelerated Cost Recovery System (MACRS) depreciation method. The MACRS method establishes prescribed depreciation rates for an asset within a specified class.
34. Straight Line Depreciation. The analysis gives the option of using this method of depreciation.
35. Salvage value. Is the value for which the equipment could be sold after its service. The salvage value is considered an income and is taxable.
36. Depreciation life. The period of years for which the wind turbines will be depreciated.
37. Annual depreciation deduction. Represents a reduction of the value of the asset. The asset includes all the initial or capital costs involved in the installation of the wind farm. It is considered an expense and has the effect of reducing the taxable income and the money to be paid in taxes.

	A	B	C	D	E	F	G
5	Years:	0	1	2	3	4	5
6	Revenues						
7	Electrical energy for sale (kWh):	0	38,984,692.82	38,789,769.36	38,595,820.51	38,402,841.41	38,210,827.20
8	Average cost of electricity (\$/kWh):	\$0.0900	\$0.0900	\$0.0900	\$0.0900	\$0.0900	\$0.0900
9	Electrical energy gross revenue (\$):	\$0.00	\$3,508,622.35	\$3,491,079.24	\$3,473,623.85	\$3,456,255.73	\$3,438,974.45
10	Revenues Net Present Worth (\$):	\$22,029,626.42		Revenues NAW(\$):	\$3,407,970.04		
11							
12	Expenses						
13	Capital Cost (\$):	(\$14,630,000.00)					
14	Borrowed Funds (Amount to finance) (\$):	\$10,972,500.00					
15	Funds Obtained from Bonds Sales (\$):	\$0.00					
16	Annual Loan Payment 1 (\$):	\$0.00	(\$1,771,365.37)	(\$1,771,365.37)	(\$1,771,365.37)	(\$1,771,365.37)	(\$1,771,365.37)
17	Annual Principal Payment 1 (\$):	\$0.00	(\$454,665.37)	(\$509,225.22)	(\$570,332.24)	(\$638,772.11)	(\$715,424.76)
18	Annual Interest Payment 1 (\$):	\$0.00	(\$1,316,700.00)	(\$1,262,140.16)	(\$1,201,033.13)	(\$1,132,593.26)	(\$1,055,940.61)
19	Annual Loan Payment 2 (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
20	Annual Principal Payment 2 (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
21	Annual Interest Payment 2 (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
22	Bond Principal Payment (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
23	Bond Interest Payment (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
24	O & M Fixed costs (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
25	O & M Variable costs (\$):	\$0.00	(\$701,724.47)	(\$701,724.47)	(\$701,724.47)	(\$701,724.47)	(\$701,724.47)
26	Land Rights Costs						
27	Leasing Option 1 (\$):	\$0.00	(\$44,000.00)	(\$44,000.00)	(\$44,000.00)	(\$44,000.00)	(\$44,000.00)
28	Leasing Option 2 (\$):	\$0.00	(\$35,086.22)	(\$34,910.79)	(\$34,736.24)	(\$34,562.56)	(\$34,389.74)
29	Total Expenses (\$):	(\$3,657,500.00)	(\$2,552,176.07)	(\$2,552,000.63)	(\$2,551,826.08)	(\$2,551,652.40)	(\$2,551,479.59)
30	Expenses Net Present Worth (\$):	(\$18,300,167.21)		Expenses NAW (\$):	(\$2,831,024.93)		
31	Energy Production Cost (\$/kWh) per year:	(\$0.07707)	(\$0.06547)	(\$0.06579)	(\$0.06612)	(\$0.06644)	(\$0.06677)

Figure C.1: Example of Spread Sheet for Cases 1.1 and 1.2: Costs and Revenues for First Five Years.

33	Years:	0	1	2	3	4	5
34	Before Tax Net Cash Flow (\$):	(\$3,657,500.00)	\$956,446.29	\$939,078.61	\$921,797.77	\$904,603.33	\$887,494.86
35	Before Taxes Cumulative Cash Flow (\$):	(\$3,657,500.00)	(\$2,701,053.71)	(\$1,761,975.10)	(\$840,177.34)	\$64,425.99	\$951,920.85
36	Before Taxes Net Present Worth (\$):	\$3,729,459.21					
37	Before Taxes Net Annual Worth (\$):	\$576,945.11					
38	Before Taxes Internal Rate of Return (%):	27.015%					
39	Uniform Series Payback Period (Years):	3.2					
40							
41	Before Taxes Net Income (\$):	\$0.00	\$1,411,111.66	\$1,448,303.82	\$1,492,130.01	\$1,543,375.44	\$1,602,919.63
42	MACRS Recovery Allowance (%):	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%
43	MACRS Annual Depreciation Deduction (\$):	\$0.00	(\$548,625.00)	(\$1,056,139.70)	(\$976,845.10)	(\$903,695.10)	(\$835,811.90)
44	MACRS 5-Year Recovery Allowance (%):	0.000%	20.000%	32.000%	19.200%	11.520%	11.520%
45	MACRS 5-Year ADD for Wind (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
46	SL Annual Depreciation Deduction (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
47	Taxable Income (\$):	\$0.00	\$862,486.66	\$392,164.12	\$515,284.91	\$639,680.34	\$767,107.73
48	Taxable Income with Incentives (\$):	\$0.00	\$862,486.66	\$392,164.12	\$515,284.91	\$639,680.34	\$767,107.73
49	Tax. Income with Inc. and Carry Forward (\$):	\$0.00	\$862,486.66	\$392,164.12	\$515,284.91	\$639,680.34	\$767,107.73
50	Income Taxes (\$):	\$0.00	(\$301,870.33)	(\$137,257.44)	(\$180,349.72)	(\$223,888.12)	(\$268,487.70)
51	After Taxes Net Income (\$):	\$0.00	\$560,616.33	\$254,906.68	\$334,935.19	\$415,792.22	\$498,620.02
52	Carry Forward (\$):	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
53							
54	Years:	0	1	2	3	4	5
55	After Tax Cash Flow (\$):	(\$3,657,500.00)	\$654,575.96	\$801,821.16	\$741,448.05	\$680,715.21	\$619,007.16
56	After Taxes Cumulative Cash Flow (\$):	(\$3,657,500.00)	(\$3,002,924.04)	(\$2,201,102.88)	(\$1,459,654.83)	(\$778,939.62)	(\$159,932.46)
57	After Taxes Net Present Worth (\$):	\$1,397,439.00					
58	After Taxes Net Annual Worth (\$):	\$216,182.98					
59	After Taxes Internal Rate of Return (%):	19.822%					
60	Uniform Series Payback Period (Years):	4.7					

Figure C.2: Example of Spread Sheet for Cases 1.1 and 1.2: Cash Flows for First Five Years.

64	Years:	0	1	2	3	4	5
65	Actual Dollars Net Cash Flow (\$):	(\$3,657,500.00)	\$654,575.96	\$801,821.16	\$741,448.05	\$680,715.21	\$619,007.16
66	Cumulative Actual Dollars Cash Flow (\$):	(\$3,657,500.00)	(\$3,002,924.04)	(\$2,201,102.88)	(\$1,459,654.83)	(\$778,939.62)	(\$159,932.46)
67	Constant Dollars Net Cash Flow (\$):	(\$3,657,500.00)	\$654,575.96	\$801,821.16	\$741,448.05	\$680,715.21	\$619,007.16
68	Cumulative Constant Dollars Cash Flow (\$):	(\$3,657,500.00)	(\$3,002,924.04)	(\$2,201,102.88)	(\$1,459,654.83)	(\$778,939.62)	(\$159,932.46)
69	Actual Dollars Net Present Worth (\$):	\$1,397,439.00					
70	Actual Dollars Internal Rate of Return (%):	19.822%					
71	Constant Dollars Net Present Worth (\$):	\$1,397,439.00					
72	Constant Dollars Internal Rate of Return (%):	19.822%					

Figure C.3: Example of Spread Sheet for Cases 1.1 and 1.2: Inflation Analysis for First Five Years.

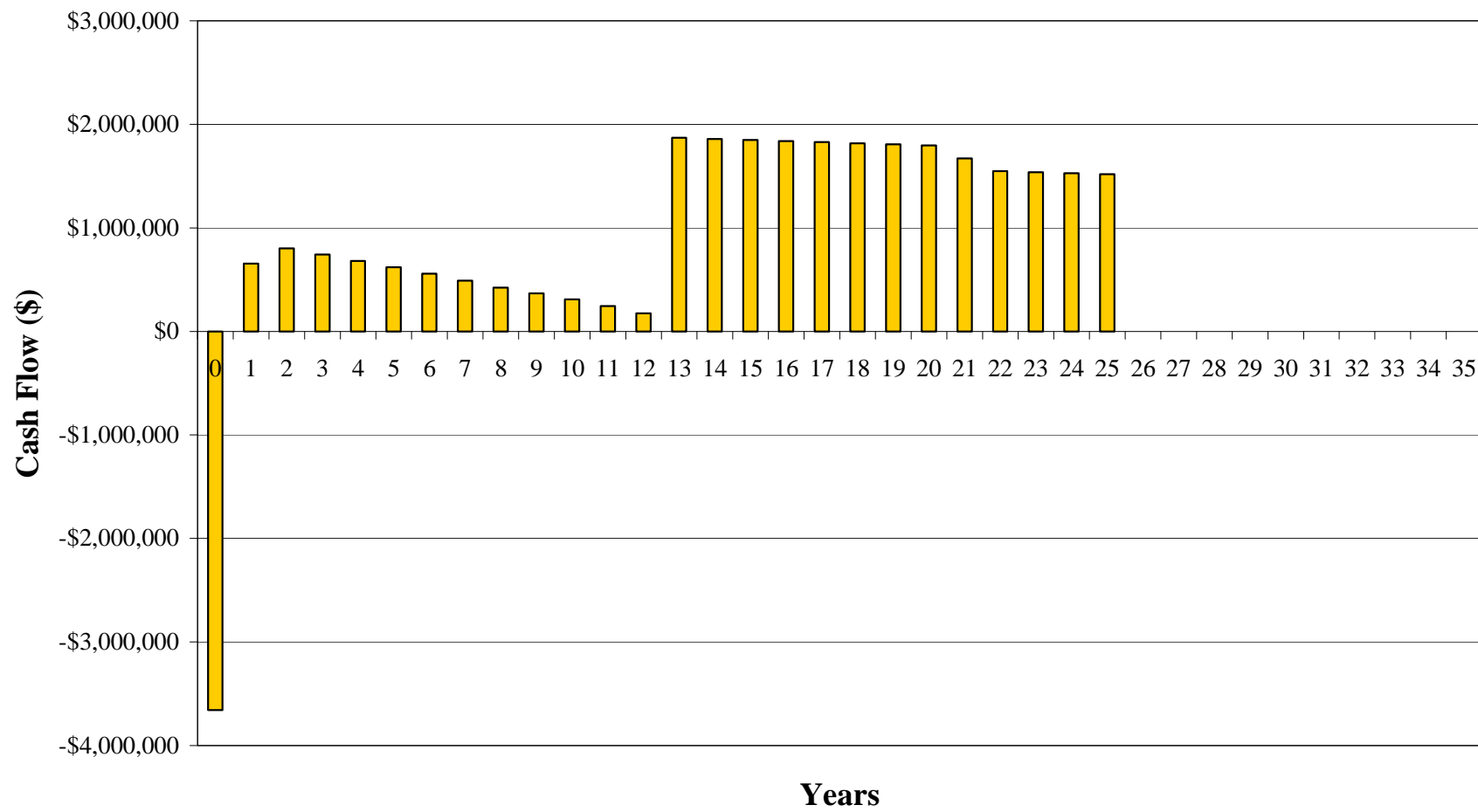


Figure C.4: After Taxes Cash Flow Diagram for Case 1.2.

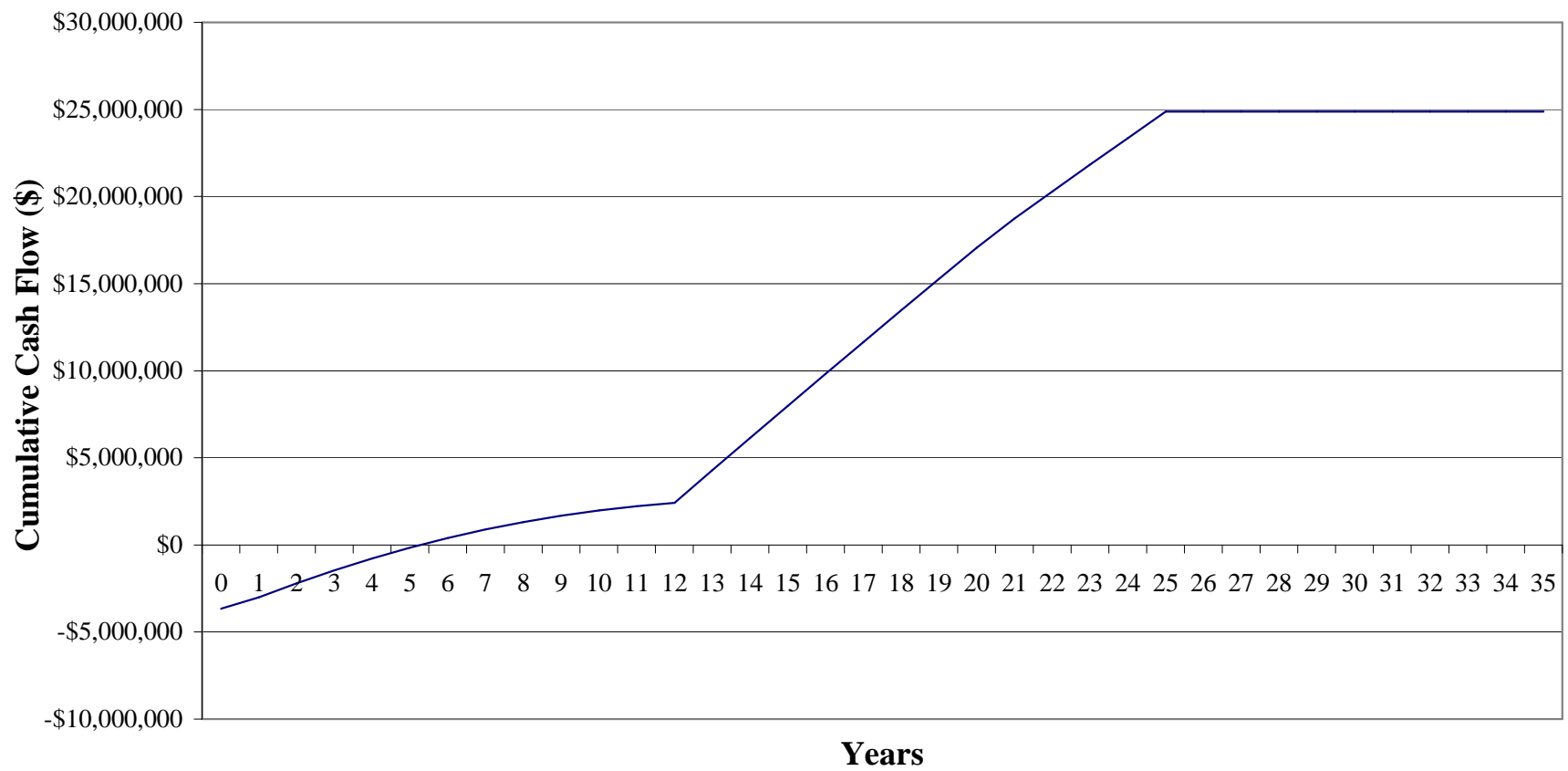


Figure C.5: Cumulative After Taxes Cash Flow Diagram for Case 1.2.