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RESOURCE-RESERVE ECONOMIC AND FINANCIAL ANALYSES OF UTILITY-SCALE SOLAR PHOTOVOLTAIC INVESTMENT IN INDIA

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ABSTRACT

Since its inception in 1839, solar photovoltaic (PV) technology has grown to become a reliable and convenient source of large-scale electricity generation. With $140.4 billion invested into PV generation globally in 2012, utility-scale PV investment opportunities are continuing to grow as a result of attractive incentives from government policy initiatives. India in particular has ambitious solar policies, which have driven incentives to invest in utility-scale PV plants. To accommodate the increase in utility-scale PV investment opportunities, this report presents a new method for classification and quantification of solar resources and solar reserves. Adapted from the USGS, this new method provides the foundation of solar energy resource economics upon which investors can make rationalized decisions to invest or not invest in utility-scale PV. Through utilizing the resource-reserve system, this report aims to justify investment in utility-scale PV in India

The resource-reserve method of solar economics is applied through economic and financial analyses. It is crucial that potential PV investors develop an understanding of the technical factors that underlie the basic operation of PV technology in the conversion of the solar resource into electricity. PV conversion of the solar resource predicates the classification of the solar resource into solar reserve classifications. While solar resources are classified by measurement method, solar reserve classifications depend on the amount of the solar resource successfully converted and the economic viability of its conversion into electricity. Economic viability of solar resource PV conversion depends on the levelized cost of electricity (LCOE), selling price of PV-generated electricity, government incentives, and quantity of PV-generated electricity demanded. A utility-scale PV investor’s goals are to maximize the solar reserve by minimizing LCOE while maximizing cash inflows from sale of electricity and government incentives (i.e. LROE).

Regional factors of the sun-earth relationship affect solar resources, while regional economic factors affect solar reserves. The regional-dependent relationship of the sun and earth impact the quality and quantity of solar resources as it varies largely according to solar altitude; with a higher solar altitude, the sun’s irradiance travels through less air mass, which allows more of the solar resource to reach the surface of the earth. As a result of the low latitude, which increases solar altitude, India is exposed to a large average daily solar irradiance ranging 4.75 to 6.00 kWh/m^2. A large solar resource sets a low LCOE as it increases the solar resource capable of PV conversion. Regional economic factors in India are mostly conducive to utility-scale PV development. PV-generated electricity prices (PPA rate) compete against local market electricity prices in India and reflect similar values. As about 59% of electricity is from coal-fired power plants and 9% from gas-fired, electricity prices are highly dependent on coal and gas prices, which are projected to increase. Additionally, India’s regions experience large electricity deficits ranging from 4.57% to as high as 16.02%. Increasing fuel costs and lack of energy supply place upward pressure on market prices. As PV LCOE continues to decrease and Indian electricity rates continue to rise, PV grid parity is set on a fast-track in India, which increases the solar reserves in the region. Although having government enforcement issues, India also hosts attractive PV incentives that assist in growing the solar PV reserve.

To determine reserve classification, a financial analysis is used to determine economic viability of solar resource conversion by analyzing LCOE, LROE, and NPV. This analysis is applied to a real-world 5 MW PV investment opportunity in Andhra Pradesh, India. The analysis yielded an LCOE of $0.146/kWh, an LROE of $0.152/kWh, and an NPV of $315,500, which indicated an economically viable PV conversion of the solar resource. This determined a total annual indicated solar resource of 81.0 million kWh with a total converted solar reserve of 9.776 million kWh; 71.3 million kWh were subeconomic resources due to reflective losses, efficiency of conversion, and expected electrical losses. The total solar reserve over the lifetime of the power plant was determined to be 230.29 million kWh. The analysis of the PV plant concluded that utility-scale PV investment in India is feasible. India’s fast-tracked PV grid-parity coupled with re-amplified enforcement of government incentives has the ability to significantly increase the solar reserves in India in the near future.

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Thanks to Dr. Jeffrey Brownson whose original work in solar resource-reserve classification provided the foundation for this report's analysis. I would also like to thank my friend, Himadeep Nallavadla, who provided the real-world PV investment data from Halo Energie Pvt. Ltd. to include in my analysis. Thanks to my mother and father whose constant support drives my motivation to perform at my best. Lastly, I would like to thank my grandfather, Maj. Gen. Pete Spragins, who taught me to never stop learning.

Chapter 1

Introduction to Solar Energy Investment

History of Photovoltaics in Electricity Generation

Solar photovoltaic technology has evolved over the course of 160 years to become a suitable source of large-scale electricity generation.[1] French physicist Edmund Becqurel first discovered in 1839 that certain materials with specific conductive properties emitted electrons with increased exposure to light, known as the photovoltaic effect.[1] However, this early discovery of electron emissions was not deemed useful for electricity generation applications until 1950 with the beginning of the space race. Governments looking to launch satellites and spacecraft into orbit required a form of generating useable energy that decreased design complexity and provided long-term applications. Photovoltaic (PV) cells proved ideal for space applications due to the abundant solar resource outside of the Earth's atmosphere and lack of fuel requirement. The first noteworthy application of PV cells for electricity generation was for use on the Vanguard I satellite in 1958.[1] Development of PV cells for space applications advanced the technology significantly in a short period of time. PV applications for operations on Earth were first used for telephone systems and radio transmitters in remote communities without access to suitable electrical infrastructure.[1] Additionally, solar PV technology was utilized widely in developing countries for pumping water, powering schools, and medicinal refrigeration applications.[1]

The most notable development in photovoltaic technology with respect to large-scale power generation occurred with the energy crisis. Oil shortages in the 1970s spurred technology development in PV cells for use in electricity generation. The US government founded what is now the National Renewable Energy Laboratory to lead PV energy research.[1] In addition to enhancing PV technology, materials, inverters, and interactive systems, these initiatives launched federal legislation promoting tax credits and other solar PV subsidization to promote its development. PV incentive programs became available in the US, Europe, and Japan.[1] In the early 1960 solar applications, solar PV cells were about $1000 per watt of power.[1] Early expensive solar cells such as these were acceptable for use in space, which were funded by large government budgets; however, typical end-users required much less expensive materials in order for PV to be financially feasible investments. Through the increase in solar technology development and manufacturing improvements, solar cells have since then dropped to a cost of less than $4 per watt.[1] As the cost of solar PV has been following a downward trend, the cost of fossil fuels has experienced an increasing trend, which has subsequently increased the cost of conventional electricity production. The combination of this cost increase and subsidization has allowed solar PV electricity generation to compete with fossil fuel electricity generators.[1]

Utility-Scale Photovoltaic Power Generation

From 2000-2011, solar PV was the fastest growing renewable power technology in the world.[2] In 2012, solar PV reached the benchmark figure of 100 GW of global installed capacity, which represents an increase of 41% from the previous year.[3] The installed capacity of PV was only about 10 GW globally in 2007 and has since then increased exponentially by 900%.[3] The countries with the largest installed PV capacities are Germany (~32.4 GW), Italy (~17 GW), China (~8.3 GW), USA (~7.8 GW), and Japan (~6.9 GW).[4] A total of 31.1 GW of PV systems were installed in 2012, and this annual installation figure is expected to grow to 48 GW by 2017.[4] Declining PV costs is projected to drive PV growth along with increased installation in the many countries that have only tapped a small portion of their overall solar PV energy potential, such as Australia (~ 2.4 GW) and India (~ 1.2 GW).[4] Countries with excellent solar resources, such as Africa, the Middle East, Southeast Asia, and Latin America, are just beginning development of solar PV energy, which will assist in driving global capacity growth.[4] In addition to declining costs, PV growth will be dependent on adequate support systems in the form of policies imposed by governments to further incentivize solar PV development. Regions with strong support systems and streamlined solar power development procedures will experience the most growth.[4] Figure 1 displays a chart depicting global installed capacity from 2001-2013 and this forecasted capacity growth to 2015.

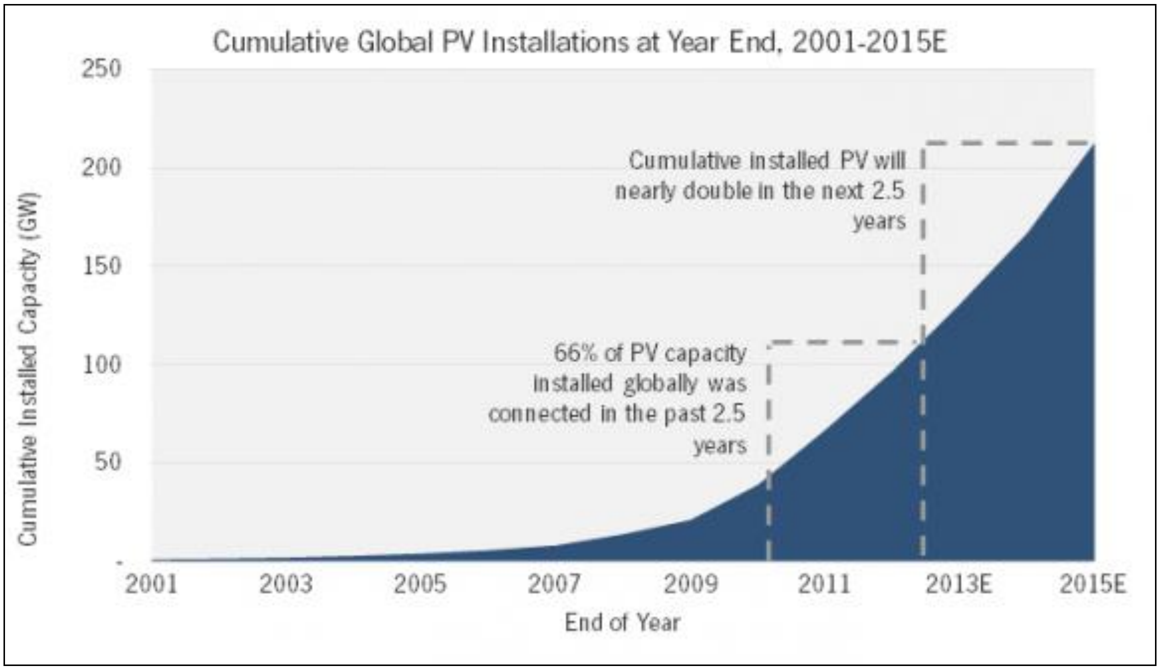

Figure 1: Global Installed PV Capacity[5]

The statistics of installed PV capacity are determined by solar PV systems that are connected to electrical grids. The most significant sources of PV installation growth are from grid-connected rooftop systems and utility-scale applications.[4] Utility-scale power plants have a capacity of 1 MW or larger (definition of "utility-scale" varies) and consist of thousands of solar modules to generate large-scale electricity.[1] The inherent limitation of these solar power plants is that they can only operate during the day when there is adequate sunlight. Fluctuating weather conditions also create variable electricity generation output.[1] These power plants require a large area of land to produce significant power. While the cost of solar has declined significantly, the technology remains more costly than other forms of conventional electricity; therefore, developers of utility-scale solar must secure subsidization or incentives from renewable policies, which can be a lengthy and difficult process. Conversely, these systems also have significant advantages over conventional electricity generators. PV technologies can be deployed much faster than conventional power plants as a result of simpler designs and components that are much easier to install than those in other power plants.[1] While utility-scale PV plants can be installed in several months, conventional power plants (i.e. nuclear, coal-fired, and gas-fired) may take as long as several years to install. In addition, PV power plants can be installed incrementally and can connect additional capacity throughout the plant's life, while conventional plants require very expensive construction processes to increase capacity.[1] The most significant inherent advantage of solar PV power plants is the lack of fuel requirement for operation; this represents significant savings in fuel costs for electricity that would otherwise be generated via combustion of fossil fuels. Another advantage of solar utility-scale systems derives from the value consumers place on renewable energy.

Investment in Utility-Scale Photovoltaic Electricity Generation

The forecasted growth trend of solar PV along with the availability of incentives has created large global energy investment opportunities. Utility-scale solar power plants can represent a lucrative investment with valuable incentives. Solar PV investment in 2012 alone was $140.4 billion globally.[3] Investment in large-scale solar projects of 1 MW or greater was about $69 billion in 2011 and $52.7 billion in 2012—the decrease in investment in 2012 was primarily due to the dramatic decrease in PV costs.[6]

Large-scale solar energy investors make return on their investments by selling electricity using several different methods, which largely depend on the location, electricity generation regulations, and solar policies in place. Grid-connected solar power plants over 1 MW are typically wholly owned and operated by the investors/developers that have a prearranged agreement with an electricity consumer or end-user; this agreement is known as a power purchase agreement (PPA).[7] A solar power plant developer agrees to sell all or a portion of the plant's electricity generation to the PPA consumer in return for a fixed or escalating price; a power plant can have a single PPA or many depending on the size of the plant.[7] The developers also receive a policy-driven form of tax incentive and/or subsidization (e.g. renewable energy credits) in addition to PPAs, which varies by the country in which the power plant is installed. Alternatively, electricity can be supplied to utilities in exchange for a government-funded feed-in tariff. Feed-in tariffs are policy mechanisms featuring long-term payment contracts to renewable energy developers that are priced based on the relative cost of the specific renewable energy.[8] Developers that fully own and operate solar power plants using PPAs and/or feed-in tariff methods are typically referred to as independent power producers (IPPs), as opposed to public utility power generators. While solar IPP investors currently gain adequate return on investment with the aide of tax incentives and subsidization, solar PV is expected to reach an unsubsidized competitive cost—known as grid parity—in the future as the cost of solar continues to decrease and the price of electricity continues to increase. These corresponding cost trends are expected to cross, at which point solar PV will be cost-competitive with other forms of electricity generation without the need for subsidization.[9]

The barrier to entry into the solar market for IPPs has decreased significantly in countries with substantial solar incentives, which has created many energy investment opportunities in the solar industry. India, in particular, is very well suited for solar PV investment. In addition to recent improvements in renewable policy, India is home to an excellent solar resource of about 300 sunny days per year.[10] In order to reach a target of 20,000 MW of solar PV by 2022, the Central Government of India has released the National Solar Mission detailing policies of tax benefits and renewable energy credits.[10] To support the National Solar Mission, many Indian states have created complementing state policies enforcing renewable purchase obligations from entities consuming large-scale fossil fuel generated electricity.[10] The growing Indian middle class has also contributed significantly to electricity demand; as a result of high demand, India has an electricity deficit between 10% and 13% of daily demand, placing upward pressure on electricity prices.[10] Increasing electricity prices coupled with decreasing PV costs set Indian solar grid-parity on an accelerated path and facilitate utility-scale PV investment opportunities in India.

Report Objectives

Given this increase in investment opportunities for solar PV, it is important for investors to be capable of rationalizing decisions to invest in utility-scale PV systems. This report utilizes the fundamental principle that an investor will choose to invest or not invest in a utility-scale PV system based on whether or not conversion of the solar resource into electricity via the system is economically viable. To aide in the rationalization of utility-scale PV investment decisions, this report presents a new method to determine the economic viability of a PV system through classification of the solar resource and solar reserve at the system's location. The solar resource-reserve system classifies and quantifies solar energy in a similar manner to geological resources (e.g. coal, minerals, geofuels) based on the United States Geological Survey methods. This system provides the foundation of solar resource economics upon which individuals, firms, and investors can make rationalized decisions on the PV electrical conversion and allocation of the solar resource.

This report aims to justify IPP investment in utility-scale solar PV in India via the solar resource-reserve classification system. After providing an understanding of the technological factors of solar energy conversion, which are independent of regional application, the report details the methods used for the solar resource-reserve classification system and applies it to the specific case of utility-scale PV investment in India. To quantify the solar resource, the regionally dependent sun-earth relationship present in India was analyzed with respect to PV application and solar energy measurement. The determination of the solar resource into solar reserve classifications for PV technology was largely determined by the regional economic conditions for PV electricity generation. As such, the solar PV economic climate in India was scrutinized by an economic analysis of its existing electrical infrastructure, the Indian electricity market detailing energy supply/demand and pricing, Indian PV solar policy and financial incentives including related issues, and relevant costs of PV development used in the determination of levelized cost of electricity (LCOE).

These regional factors were utilized in a financial analysis for the classification and quantification of the solar resource and reserve of a real-world utility-scale PV investment opportunity in Komreddypalle, Andhra Pradesh, India. The solar resource was determined by Indian measurements at the project location, which were used in conjunction with PV system modeling software to determine the total amount of the solar resource converted into electricity. A financial analysis of the PV electrical conversion of the solar resource was used to determine and quantify the solar resource into solar reserve classifications. After presenting basic financial analysis principles, the study utilized PV IPP industry costs and PPA assumptions to determine the net present value (NPV), internal rate of return (IRR), and LCOE of the PV system. Conjointly with a financial sensitivity analysis, the report defines the total solar resource, subeconomic solar resources, and solar reserves present at the Indian project location to conclude the feasibility of the Indian utility-scale PV investment opportunity.

Chapter 2

Technical Factors of Solar Photovoltaic Development

Importance of Technical Factors Affecting Solar Photovoltaic Investment

Investing in solar energy has the ultimate goal of any investment: a positive rate of return, or a positive net present value. As in all cash generating assets, solar energy investments create cash flows driven by revenue. Solar photovoltaic technology creates revenue through the sale of electricity. Electricity is a readily usable form of energy that photovoltaics generate via conversion of sunlight into electric current. The materials and processes used to convert sunlight into usable electricity underlie the creation of cash flow, which drives revenue creation. The solar industry has grown significantly in recent years, providing many different products and qualities. Certain manufacturers boast superior products with higher electricity generation potential, while others boast inexpensive yet effective products. With this large variation in electricity generation potential, PV products are also subject to a wide range of prices. While high quality PV components may be successful in generating electricity to drive revenue, a significant capital cost of materials can entirely negate large revenues, thereby decreasing profitability. To support generation of net profits, solar energy investment is supported by PV components that meet a level of electricity generation complemented by a low relative cost. A useful metric to identify this trait is cost per kilowatt-hour ($/kWh), which denotes the cost of solar PV components and operation per unit of electricity. This metric is the LCOE; LCOE is very important and widely used for the comparison of electricity generation technologies.[11] A low cost per kilowatt-hour associated with solar PV generally indicates an intelligent product choice for investment.[11] LCOE is determined through many factors and is covered in greater detail in Chapter 3. In order to be sufficiently capable of analyzing revenue generation and LCOE, the technical factors affecting the basic operation of PV technology must first be understood.

Photovoltaic Electrical Conversion

The overall process of solar energy conversion via photovoltaics can be summarized as the conversion of sunlight, or solar irradiance, into electricity. The means by which this occurs begins at the atomic level. All atoms consist of neutrons, protons, and electrons. Electrons exist in areas surrounding the atom's nucleus and can occupy areas close to the nucleus and farther from the nucleus. The electrons that reside closer to the nucleus of the atom experience much greater atomic attraction to the nucleus, and thus are not free to interact with other atoms. The electrons that reside further from the nucleus experience less attraction to the atom's core and are more free to interact with other atoms. The shell of space in which the outermost electrons reside is known as the valence band. Electrons in the valence band can be excited to higher levels of energy, which can then allow them to interact with other atoms; the movement of valence band electrons to interactions with other atoms is the principle of conduction.[12] The outermost valence band electrons capable of this movement reside in the conduction band.[12] The difference in energy level between an electron in the valence band and one in the innermost conduction band shell is referred to as the band gap.[12] This band gap defines types of material in terms of electrical conductance. For example, a material that has a valence band full of electrons with a vacant conduction band tends to have a high band gap; these materials are known as insulators and are unable to conduct electrons under normal conditions.[12] A material that has an empty valence band with a partially full conduction band are known as conductors; these materials have valence bands and conduction bands that overlap, allowing electrons to easily become free to conduct electricity.[12] Materials that have a partially full valence band with an almost empty (very few electrons) conduction band have intermediate band gaps; these materials are known as semiconductors.[12] Electrons in the valence band of a semiconductor can be easily excited by radiation to "jump" the band gap into the conduction band where they can then move freely to conduct electricity.[12] This is the principle behind the photovoltaic effect.[12]

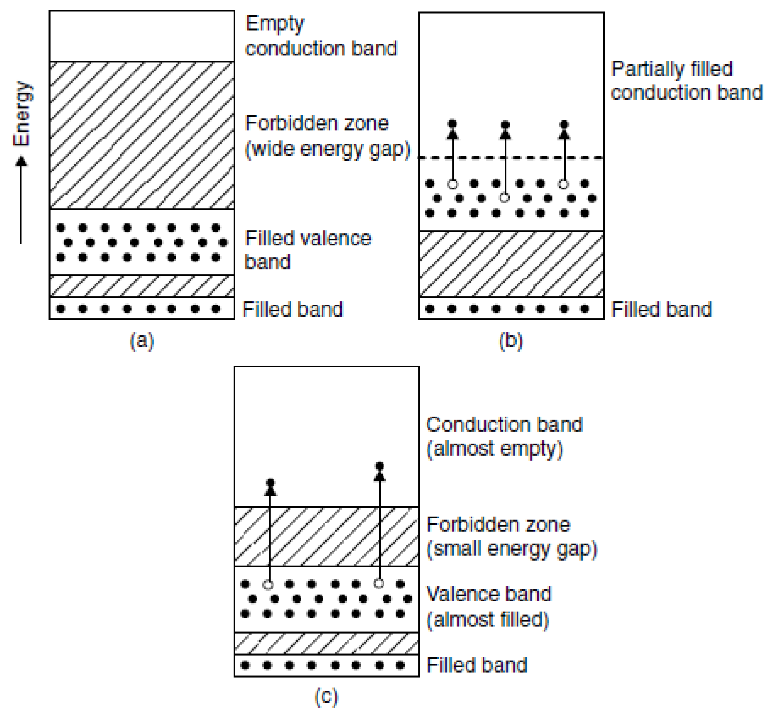

Figure 2: Energy Bands of an Insulator (a), Conductor (b), and Semiconductor (c)[12]

While semiconductors easily allow excited electrons into the conduction band, a current cannot be created from the electrons without directionality.[12] Through a process referred to as doping, other types of atoms are used to replace the atoms within a semiconductor. Doping is used to adjust the electronic characteristics of the band gap of a semiconductor by creating more negatively charged (more electrons, "n-type") or more positively charged (less electrons, "p-type") semiconductors.[12] Combining n-type and p-type semiconductors provides directionality to electrons in the conduction band, thereby creating an electrical current.[12] This n-type and p-type combination is the composition of the photovoltaic material within a solar PV cell. When a PV cell absorbs solar radiation with enough energy to promote electrons above the band gap to the conduction band, the directional excitement of electrons creates voltage (i.e. potential causing the electrons to move) and current (i.e. movement of electrons) across the cell.[12] Silicon doped with Boron and Phosphorus is the most commonly used semiconductor in commercial PV cells; however, there are several other materials that compete with Silicon-based semiconductors in commercial PV cell manufacturing. The effectiveness and efficiency in utilizing sunlight to promote electrons to the conduction band is the fundamental component affecting the amount of electricity that PV cells are able to generate.

Technical Factors of Electricity Generation

In order to promote current generation, PV cells contain metal grids and antireflection coatings along with the active photovoltaic material.[12] The metal grids enhance the collection of current at the front and back of the cell. Antireflection coatings enhance the absorption of sunlight by deterring reflection of the light. Each individual cell creates two important parameters: short circuit current (I_{sc}) and open circuit voltage (V_{oc}). The short circuit current is the current generated through the solar cell when the voltage across the cell is zero and is the largest current that the solar cell can produce.[13] This parameter varies according to the area of the solar cell, the power of the incident light source, the wavelength spectrum of the incident light source, absorption/reflection properties of the cell, and collection probability properties of the cell.[13] Therefore, I_{sc} greatly differs among manufacturers and different material types of PV cells. Silicon PV cells have a maximum I_{sc} of about 46 mA/cm^2 under industry standard solar conditions, while commercially used Silicon PV cells have short circuit currents that range from 28-35 mA/cm^2.[13]

Conversely, open-circuit voltage is the voltage that a solar cell has under conditions when net-current is equal to zero. This is the maximum voltage a solar cell can have.[13] Among other factors, V_{oc} depends primarily on the electrical current properties of the cell.[13] High quality silicon cells have open circuit voltages of about 730 mV under standardized atmospheric solar conditions, while most commercially used PV cells have open circuit voltages of about 600 mV.[13]

Short circuit current and open circuit voltage are key parameters used in defining the potential power output of solar PV cells. The power output of a solar cell is the product of the current and the voltage of the cell at a given point in time; the solar industry uses IV curves (i.e. current vs. voltage curves) to depict the power output. Figure 1 shows a typical IV curve.

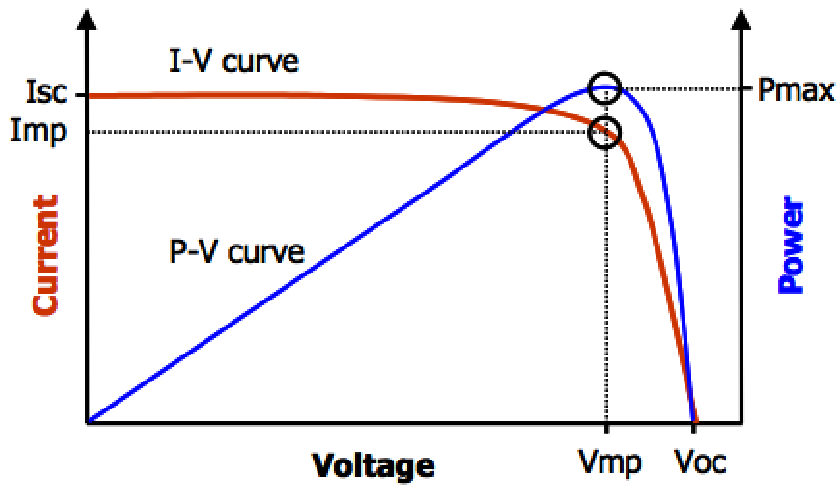

Figure 3: IV curve of a solar cell example[14]

Figure 1 depicts the short circuit current on the y-axis and the open circuit voltage on the x-axis. The PV curve is shown in blue and represents the power of the cell according to the current and voltage at a specific point. The power of the cell peaks at the point labeled P_{max}. The current and voltage at which the cell operates at maximum power are denoted I_{mp} and V_{mp}, respectively. IV curves and their respective power curves also vary widely according to solar conditions, photovoltaic material, cell size, and solar manufacturer.

Solar PV cells can be made with either single crystalline silicon or multi crystalline silicon. Single crystalline silicon cells typically support better overall performance than multi crystalline silicon, but are more expensive.[13] The PV cells are electrically packaged together into a module to create an area of practical power production. A typical solar module has 36 individual PV cells connected in series to increase the overall voltage of the power unit (voltages of cells in series are additive).[13] Figure 2 depicts the typical orientation of the PV cells connected in series.

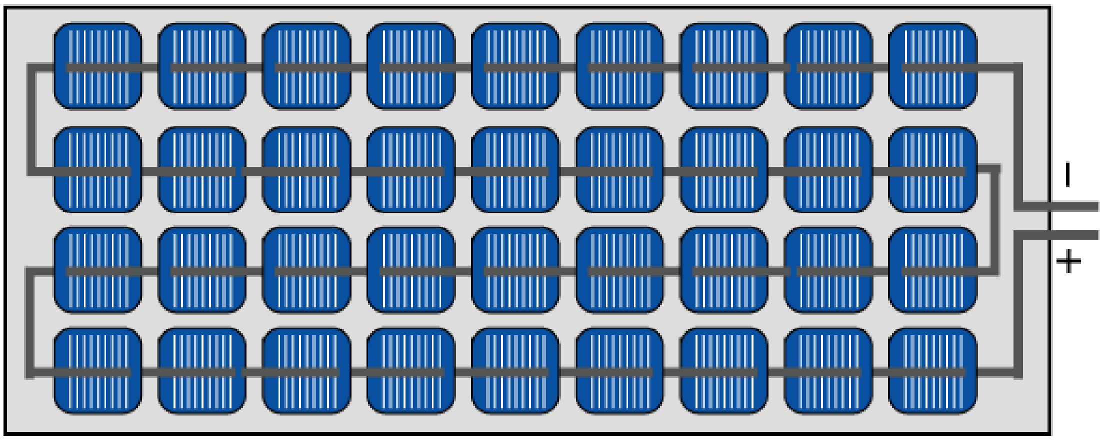

Figure 4: PV module with 36 cells connected in series[13]

One popular PV cell set up used by the solar industry, shown in figure 2, has 4 rows of 9 cells each.[13] Silicon cells are typically about 0.6 V at industry standard conditions; a module with this configuration would have an overall open circuit voltage of about 21 V.[13] While the voltage of a module depends on the number of cells in the module, the current of the module depends on the area of the individual cells. All PV cells must be of the same size to prevent a current mismatch, which lowers the overall efficiency of the module.[13] Individual PV cells are often sized to 100 cm^2 to give an overall module current of about 3.5 A at industry standard conditions.[13] Therefore, the power output of a module depends on the manufacturer's specific arrangement and size of PV cells within the module.

Solar modules are placed in configurations referred to as an array. Arrays of modules consist of a number of modules connected electrically in series—a string of modules—which are connected in parallel to other strings of modules. The exact configuration of the array depends on the required power and electrical specifications of the plant. The total number of modules used determines the overall power of the power plant. As voltages of modules connected in series is additive, the number of modules in a string determines the voltage of the power plant. The number of strings a power plant has connected in parallel determines the current of the power plant. Each array is connected to a single inverter. A single power plant can have as many arrays and inverters as is necessary to meet the desired power requirement.[15]

The current created by solar modules is direct current (DC), which denotes that electrons are only moving through the electrical wires in a single direction. All significant power grids that solar PV plants feed into operate with alternating current (AC). Alternating current has electrons moving in changing directions caused by the oscillation of voltage. For example, households in the United States operate on 120-volt AC electricity with the electrical voltage oscillating in a sine wave from 170 V to -170 V at a frequency of 60 cycles per second.[16] In order for the DC current generated from solar PV to be properly fed into the electrical grid, the electrical current must be synchronized with the utility line via the use of inverters.[15] This type of inverter is referred to as a grid-tie inverter. These inverters utilize an onboard computer to sense the alternating current and voltage of the utility grid to synchronize the DC electricity into AC electricity that matches that of the grid.[15] Inverters have specific electrical requirements published by the manufacturer that the array design must conform to in order to ensure optimal power production.

One of the most important aspects of solar energy development is solar design, which involves the matching of solar PV arrays to inverters. Solar energy investors must be capable of completing this in order to validate the optimal solar design created by subcontracted designers or to design power plants in-house by the investor to cut engineering costs. This process is completed by utilizing the manufacturer-published specifications of the modules and inverters to maximize power production. Optimal array to inverter matching ensures that the inverter successfully converts a significant percentage of generated DC electricity to usable AC electricity.[15] It is also important to ensure that the inverter is operating near full power during periods of maximum power production when solar conditions are the most favorable.[15] An improper design can cause significant portions of solar PV energy production to be released as waste heat, which can represent aggregates of thousands of dollars in lost annual revenue for large systems. In addition, array-inverter matching must meet specific National Electrical Code (NEC) standards or standards dictated by the equivalent organization in the country of development to comply with electrical safety regulations. Refer to Appendix A for an example of array to inverter matching solar PV system design.

Another important technical factor affecting solar PV electricity generation is the effect of temperature at the PV system's location with respect to the solar irradiance (i.e. power of sunlight). It is commonly misunderstood that high temperature positively impacts solar PV cells, allowing them to generate more electricity. In fact, the opposite is true. High temperatures tend to decrease the open-circuit voltage of solar cells, which decreases electricity generation; conversely, low temperatures tend to increase open-circuit voltage, which increases electricity generation.[1] The solar irradiance that the solar cells collect has a positive correlation to the amount of electricity generated; more electricity is generated with a larger amount of solar irradiance collected.[1] Non-zero angles of incidence of the collected irradiance also create losses due to undesirable reflectance of the sunlight rather than absorption. Given the temperature, measured irradiance, and expected losses in a location, solar PV software can calculate the amount of electricity generated by determining the power at which a PV system operates throughout the day (covered in greater detail in chapter 3).[1]

Photovoltaic technology has been continuously improving as it is more widely adopted as a source of electricity generation. Efficiencies of both modules and inverters have been improving, and alternative photovoltaic materials have been studied to reduce cost and decrease manufacturing time.[17] Silicon semiconductors account for about 90% of the semiconductors utilized by the photovoltaic industry; the industry's reliance on the material causes dependence on high silicon pricing.[17] The efficiency of commercially-used silicon PV cells are around 14-15%

efficient, while laboratory-based research cells have reached efficiencies of close to 40%.[17] Among the alternative PV materials being utilized are polycrystalline thin-film materials and III-V multijunction materials.[17] Polycrystalline thin-film materials include cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS) thin-film cells.[17] CdTe PV cells feature high absorption of light through the top layers of the cell and a simple composition which allow for faster manufacturing of cells.[17] CIGS solar cells are the most efficient alternative form of solar photovoltaic material that have been adopted on a commercial scale.[17] A disadvantage of these thin-film technologies is their lower efficiencies of about 13%.[17] The III-V multijunction cells utilize inverted metamorphic multijunction technology and have achieved the highest PV efficiency ever recorded of over 40%.[17] The National Renewable Energy Laboratory aims to significantly lower the cell cost of this technology to promote commercial adoption.[17]

Photovoltaic Investment Based on Technical Factors

For solar PV investors aiming to successfully compete on a global scale, backgrounds in photovoltaic operation, development, design, and emerging technologies covered in this chapter are essential factors in solar investment strategy. In order for solar energy investors to operate competitively, they must have a thorough understanding of the materials and design aspects of solar development. While this is especially true for investors that complete engineering and design in-house, a thorough understanding is also important in order to be aware of the costs outlined by subcontracted design work. Emerging technologies must be taken into consideration in deciding when the investor may be capable of benefitting from the use of a new technology. Furthermore, fundamental knowledge of photovoltaics enhances the investor’s ability to strategically minimize their LCOE by maximizing electricity production while minimizing costs.

Chapter 3

Solar Energy Resource Economics

Solar Energy as a Commodity

Adequate solar economics requires a new method of analysis of the solar resource to rationalize why an investor makes the decision to invest in solar energy. All forms of electricity require the conversion of energy from one form to another. As aforementioned, solar energy derives from light from the sun (solar irradiance) that can be converted into other useful forms of energy. In the case of photovoltaics, solar energy is directly converted into electricity at the point of solar energy collection. Conventional electricity generation, such as coal-fired power generation, requires the combustion of a fuel source to convert chemical energy to thermal energy, which is subsequently used to do mechanical work on a generator to create electrical energy. The fundamental economic difference between conventional electricity generation such as this and solar PV electricity generation is that fuel must be purchased to create conventional electricity. Fuel (e.g. coal, natural gas, uranium, etc) must be purchased at a market-dependent price before generation-use. This fuel is purchased directly or indirectly from the entity that extracted it from the Earth. Because solar irradiance cannot be physically stored in its original form (i.e. photons), no single entity can claim ownership rights on solar irradiance, which predicates the inability to sell or need to purchase solar irradiance. Thus, solar PV’s “fuel” is free. As a result, solar irradiance from the sun is not typically analyzed as a good or commodity in the manner that geofuels are; however given light’s inherent value, solar irradiance must be economically analyzed as a good.

Energy and mass can be analyzed in terms of stocks and flows.[18] A stock is an amount of stored energy or mass, similar to a fuel tank. Flows are exchanges of energy or mass that alter the stock by increasing it with inflows and decreasing the stock with outflows.[18] In conventional geofuels, stocks are made up of accumulated material in the Earth's crust, such as a coal bed or methane adsorbed into shale formations. These geofuels stocks are increased by flows from the process of decomposition of organic materials under pressure over hundreds of millions of years. Likewise, mineral stocks are increased by flow from the core of the Earth via plate tectonics and magnetic inflows.[18] Geofuel and mineral stocks are depleted via mining outflows and erosion outflows.[18] Solar energy's stock is the sun, which creates solar irradiance outflows via hydrogen fusion processes that react for billions of years.[18]

Stocks and flows vary greatly depending on the resource (i.e. geofuels vs. the solar resource). An inherent difference between geofuels and solar irradiance is the control over outflows: the flow of minerals through mining practices can be relatively increased or decreased by changing extraction rates, while solar irradiance flow cannot be adjusted. For example, the flow of natural gas from a completed well (after drilling and pipeline connection) is controlled depending on economic conditions and can even be entirely halted if desired.[19] Conversely, the flow of solar irradiance is dependent on regional climate, current weather conditions, and time—all of which cannot be controlled. Yet when measured over time, the typical annual irradiance (i.e. annual flow) of a location can be determined with relatively low uncertainty.

Following the analysis of light as a commodity in terms of flows and stocks, the value of solar irradiance can be analyzed using established resource classification methods typically used for geofuel and mineral commodities.[18] The value of light is dependent on the demand for light as a good or service and the cost of alternatives.[18] In all commodities, the amount of the good or service that is accessible is dependent on the economic viability of the good or service.[18] A commodity is only determined to be accessible if its sale/use is capable of matching or outperforming expenses associated with attaining or utilizing the commodity. To tie together the relationship of economics and commodity use viability, the US Geological Survey classification method of resources and reserves is applicable to solar irradiance for photovoltaic use.[18] Figure 5 includes a depiction of this resource-reserve and economic relationship of the solar resource specific to grid-connected PV electricity generation.

Cumulative Production amount of solar energy converted (PV-generated electricity) to date	**Identified Solar Resource** solar energy that grid-connected solar PV systems can convert		
	Demonstrated		**Inferred** geospatial mapping by interpolation
	Measured thorough irradiance measurements at PV site	**Indicated** satellite mapping	
Economic selling price of PV-generated electricity + govt. incentives is greater than LCOE	**Reserves** PV conversion of solar energy into electricity at PV site is entirely economically viable		**Inferred Reserves**
Marginally Economic selling price of PV-generated electricity + govt. incentives is approximately equal to LCOE	**Marginal Reserves** PV conversion of solar energy into electricity at PV site borders on economic viability. Solar energy would be convertible given expected changes in economic or PV technology factors.		**Inferred Marginal Reserves**
Subeconomic selling price of PV-generated electricity + govt. incentives is less than LCOE	**Subeconomic Resources** PV conversion of solar energy into electricity is not economically viable. Includes unconverted solar resources due to energy losses and land left unused for solar PV conversion.		**Inferred Subeconomic Resources**

Figure 5: Solar PV Resource-Reserve Classification[18]

Figure 5 details the system used to classify the solar resource in a single location based on measurement and economic factors. Determining economic viability is explained in further detail in the following section of this chapter. The terminology and corresponding definitions utilized by this classification system are adapted from [18] and applied specifically to PV applications:

- **Resource:** a material or energy source occurring in or on the Earth that can be feasibly extracted and/or converted. The solar resource is inclusive of all solar irradiance incident on the Earth's surface that PV technology is capable of converting into an electric current.[18]

- **Identified Resource:** includes the resources where the location, grade, quality, and quantity are known based on specific meteorological evidence and resources which have been estimated. Identified resources are inclusive of Measured, Indicated, and Inferred resources, which are further subdivided into economic, marginally economic, and subeconomic categories. The **demonstrated resource** is the portion of the resource that includes both the measured and indicated resource.[18]
    - **Measured Resource:** the portion of the resource that has been specifically measured via detailed irradiance sampling instruments (e.g. pyranometer and pyrheliometer) to determine concentration/grade of solar irradiance at the PV system site. Groups of close measurements and well-defined meteorological character of location establish variance, uncertainty, and risk associated with the solar irradiance.[18]
    - **Indicated Resource:** the portion of the resource with grade of irradiance calculated based on similar types of measuring techniques as the measured resource, but the measurements are farther apart and/or less adequately spaced over time. The indicated solar resource irradiance may be calculated using satellite determination. There is a higher degree of uncertainty in the calculation, but it is reliable enough to assume continuity between points of observation.[18]
    - **Inferred Resource:** the remaining portion of the resource with a grade of irradiance being an estimation based on the assumption of regional continuity beyond measured and/or indicated resources.[18]
- **Reserve Base:** portion of identified resources that meet the minimum physical criteria for the relevant conversion technology. The reserve base is composed of demonstrated

resources, which are further subdivided into economic and marginally economic reserves.[18] For solar PV, this represents the minimum irradiance that can be successfully converted into electricity via the photovoltaic effect and DC-AC inversion. Note that while resource classifications pertain to the physical presence and method of measurement of the resource, reserves pertain to the economic viability of extracting/converting the resource.

  - **Reserves (i.e. Economic Reserves):** the portion of the larger reserve base that can be economically extracted and/or converted at the time of resource determination; the current economic conditions must be established to be conducive to profitable extraction/conversion of the resource with reasonable certainty.[18] Extraction or conversion systems (e.g. PV modules and inverter) do not need to be in place to meet the "at the time of determination" criterion.[20]
  - **Marginal Reserves:** the portion of the larger reserve base that reaches the limit of economic uncertainty for profitable extraction/conversion of the resource at the time of determination. This portion of the reserve base would also meet economic reserves criteria with changes in market conditions or technological factors.[18]

- **Subeconomic Resources:** the portion of identified resources that cannot be economically or marginally economically extracted/converted at the time of determination. This represents the remaining portion of identified resources that does not meet reserves or marginal reserves criteria.[18]
- **Cumulative Production:** the portion of solar energy converted in the past falls into this cumulative production classification and is not a part of the resource.[18]

Using these classifications, there are several differences between mineral/geofuel resources and the solar resource that provide further context to this classification system (note: continue referring to figure 5 for this analysis). For all resources using this system, it is applicable for a single location that may contain several reserves. While minerals and geofuels only occur within some places of the Earth's crust, solar irradiance is present—according to climate, current weather conditions, and time—on the entirety of the Earth's surface. Therefore, the solar resource can be theoretically converted at any location on the Earth's surface. However, for photovoltaic solar energy conversion, the relevant solar resource only exists in locations where a solar PV system *can* practically exist based on regional factors (i.e. solar PV systems cannot be practically installed on the entire surface of the Earth). The solar irradiance that is "dedicated" to a specific potential PV system makes up the solar resource in a given locale; this resource is quantified by the solar irradiance that falls on the area of land (or rooftop) where the PV system is installed or is to be installed. The amount of solar resource incident on a surface area is dependent on the regional sun-earth relationship of the locale, which is analyzed in chapter 4.

As opposed to mineral and geofuel resources that can have many types of reserves and resources in a single formation, solar resources will typically fall under only two types of reserve and resource classifications. In the example of coal, a single coal formation may represent an identified resource that includes measured and indicated resources after determination of coal quantity and grade. This identified coal resource may also contain both categories of reserves (economical reserves and marginally economical reserves) and subeconomic resources all within a single bed of coal. The economic reserves represent the portion of the coal bed that is thick and shallow enough to economically mine, while the marginally economic reserves represent the portion of the coal bed that borders on being too thin and/or deep to economically mine.[21] The subeconomic resources represent the portion of the coal bed that is completely too thin and/or too deep to economically mine; the portion of the coal bed that is lost-in-mining also falls under subeconomic resources.[21] Conversely, the amount of solar irradiance dedicated to a specific PV system will vary negligibly across the area to be covered by the PV system unless the irradiance is decreased by non-meteorological shading effects. Because the resource is effectively identical across the relevant area, 100% of the *converted* solar resource—which is also subject to identical economic factors—will fall under a single reserve classification at a specific point in time. However, the total amount of the solar resource that is collected by PV cells will not be 100% converted into electricity. The solar resource that is left unconverted due to angle of incidence losses, efficiency of PV conversion, and expected electrical losses are classified as subeconomic resources as they are incapable of economic conversion. Additionally, a large portion of the PV site's land area will not be covered with modules due to areas covered by inverters, access roads, necessary spacing of modules, and unused sunk cost land. The solar resource incident on these areas of the land are also classified as subeconomic resources as they cannot be economically converted into electricity given the system's use of land. Every PV system will have a converted solar resource classified as a reserve, marginal reserve, or subeconomic resource, and will also have subeconomic resources to account for losses and land left unused for PV conversion.

Assuming a PV system has an adequate solar resource, the reserve classification of the converted solar resources is dependent on the economic viability of PV electricity generation. If economic conditions and government policies are conducive to PV electricity generation in a region, then all of the successfully converted solar resource will fall under the category of reserve (i.e. economic reserve). If economic conditions and government policies approach the limit of PV electricity generation feasibility, then all of the converted solar resource will fall under the category of marginal reserve. If economic conditions and government policies are not sufficient to support PV electricity generation, then all of the converted solar resource will be deemed a subeconomic resource. Alternatively, if economic conditions and government policies make PV electricity generation economical but the solar resource is not adequate to support PV electricity generation, the resource may be deemed a marginal reserve or subeconomic resource.

Economic Viability of Solar Resource Conversion

As the classification system applied to solar resources relies on the economics of solar irradiance conversion into electricity, the key fundamental factors affecting economic viability are depicted in figure 6. The most relevant factors include: the levelized cost of electricity (LCOE), the selling price of PV-generated electricity, government incentives/policies, and the quantity of PV-generated electricity demanded.[18] Each of these factors are, in turn, affected by other technical, regional, and market variables which figure 6 has included in subcategories along with the key factors. These factors are relevant assuming that development of a PV utility-scale system is practical in the relative location given area accessibility, adequate electrical grid infrastructure, and grid interconnection capability.

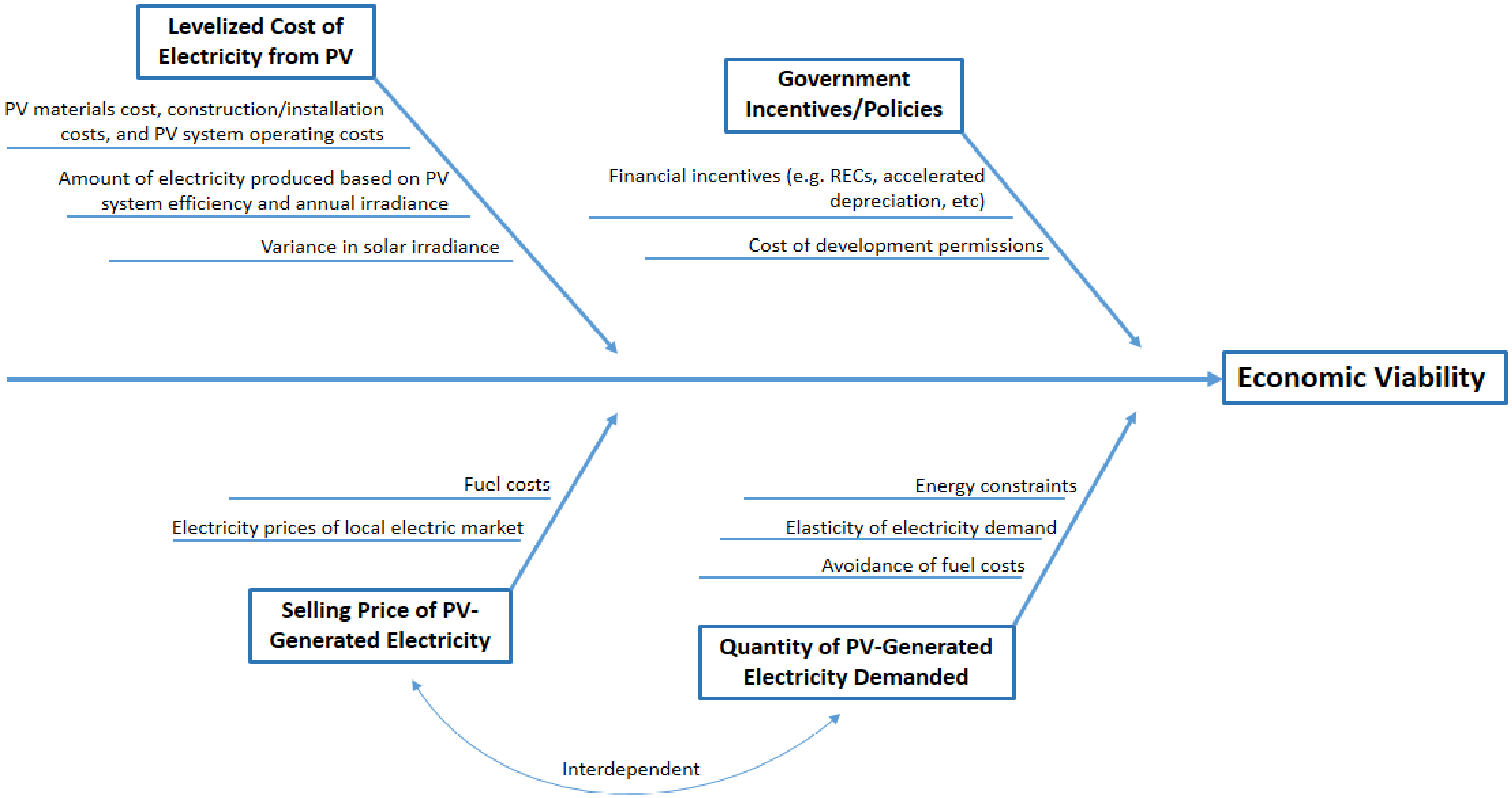

Figure 6: Factors Affecting Economic Viability

Effect of Levelized Cost of Electricity on Economic Viability

As figure 6 depicts, one of the most important metrics that the power generation industry utilizes to determine economic viability is levelized cost of electricity (LCOE). LCOE captures all cash outflows associated with developing, owning, and operating the solar PV plant for its entire lifetime; these cash outflows include all capital expenditures (equity investment covering costs of land, modules, inverters, wires, interconnection, etc.), operation and maintenance, general and administrative expenses, insurance, debt obligations, and taxes.[22] The LCOE metric is the constant cost of electricity in units of \$/kWh across the entire lifetime of the project.[22] Cash outflows are converted to the present value via discounting to account for the time value of money. Discounting future cash flows to present value is necessary to accurately sum the cash values as future dollars are not equivalent to present dollars. An example of the time value of money is that one dollar today is (usually) greater in value than a dollar one year from now. An annual rate is utilized to discount cash flows. This rate can be determined using several methods, but the most common is by calculation of the investor's weighted average cost of capital (WACC). Alternatively, the opportunity cost rate of return (i.e. the highest rate of return that the investor is capable of receiving if he/she did not invest in the relevant PV project) can be used as the discount rate. WACC and discount rates are covered in more detail in chapter 6. The simplified derivation of LCOE is provided in equations 1 and 2.[22]

$$\Sigma_t\left(\frac{(Electricity\ Sold)_{\mathrm{t}}\times LCOE}{(1+r)^t}\right)=\Sigma_t\left(\frac{(\mathrm{Cash\ Outflow})_{\mathrm{t}}}{(1+r)^t}\right) \tag{1}$$

$$LCOE=\frac{\sum_{t=0}^{T} Cash\ Outflows_t \big/ (1+r)^t}{\sum_{t=1}^{T} Electricity\ Sold_t \big/ (1+r)^t} \tag{2}$$

In these equations, *r* represents the discount rate and *t* represents the year in which the cash outflow and electricity sold is found. The numerator of equation 2 begins in year 0 to account for the cash outflows associated with setting up the project (EPC costs, capital expenditures, etc). Note that in equation 2 it appears as though electricity sold is being discounted, but this is rather a result of the algebraic derivation.[22]

A minimal LCOE is desirable and drives a PV development towards economic feasibility. As equation 2 shows, the LCOE is increased with increasing cash outflows or decreasing electricity generation; conversely, the LCOE is decreased with decreasing cash outflows or increasing electricity generation. In order to achieve a low LCOE, the PV system must minimize cash outflows while maximizing electricity generation. Most importantly, an investor can set a lower LCOE by developing the PV system in a locale with a greater solar resource to maximize electricity generation. A PV system with newer and more expensive technology may also increase the electricity generated but will also represent a large immediate cash outflow from capital expenditures, creating opposing LCOE upward and downward pressures. Likewise, a PV system with cheaper and more inefficient technology will minimize immediate cash outflows from capital expenditures but will also lower electricity generation. Additionally, inexpensive PV systems may create growing operation and maintenance costs in the future to ensure adequate production, which can increase the project's LCOE. The LCOE is further affected by the variance or uncertainty that exists in the amount of expected solar irradiance. A lower than expected solar irradiance over a project's lifetime can place upward pressure on the LCOE of a PV system; this variance must be accounted for in the risk structure of an investor's financial model.

Determining the reserve classification of the solar resource utilizes the LCOE of the project as a cash outflow benchmark figure that cash inflows must outweigh. If the sum of the selling price of the PV-generated electricity and the marginal ($/kWh) cash inflows from government policy incentives over the life of the project is greater than the LCOE, then the solar resource of the PV project is entirely economic and thus is a reserve. If this sum is approximately equal to the LCOE, then the solar resource is marginally economic and is a marginal reserve. If LCOE is larger than this sum, then the solar resource is denoted a subeconomic resource, and the PV system should not be developed.

Factors Determining the Selling Price of Electricity

The selling price of PV-generated electricity is typically determined by a PV project's power purchase agreement (PPA) made between the plant owner and a third-party electricity buyer.[7] To maximize revenue, a PV investor's goal is to maximize the specified PPA electricity price. Given that PPA prices are typically very close or lower than the retail market price of electricity, these prices are directly affected by the market price of the grid electricity in the locale of the PV system.[7] This market price is affected, in turn, by fuel costs, conventional power plant costs, transmission and distribution costs, weather conditions, and regulations.[23] In many regions, such as the US and India, the largest single sources of electricity generation are from fuel-consuming power plants, which consume mostly coal and natural gas.[23] Although coal tends to be relatively less expensive than natural gas currently, the EIA projects that natural gas-fired generation will become less expensive than coal-fired generation by 2020.[23] The construction and maintenance costs of conventional power plants directly affect the market price of electricity in order for their generation to be economical. While these power plant costs may increase the retail electricity price, they remain to be much more marginally inexpensive than solar PV power plants for the relative generation they are capable of producing.[23] The costs of maintaining electrical transmission and distribution infrastructure are as large as 42% of market electricity prices in certain regions.[23] Weather conditions widely affect the market price of electricity. Heat, experienced during summer months, increases electricity demand for cooling purposes.[23] During cold winter months, regions will demand more fuel (e.g. propane, natural gas, etc) to heat homes, which places upward pressure on fuel prices that are used to generate electricity. Finally, different regions have various government-imposed regulations that affect retail electricity prices.[23]

All of these factors are used to determine the price that PV-generated electricity is sold at before incentives. The most notable factor that indirectly affects PV electricity prices is fluctuations in fuel prices. In the long-term, the EIA's Annual Energy Outlook of 2014 projects that coal and natural gas prices will continue to increase as finite fuel reserves become diminished. According to this report, this long-term effect is a result of increasing extraction costs as fuel production efforts target new fuel reserves that are more expensive to extract after depleting less costly reserves. As these fuel prices continue to increase over time, the retail price of electricity is also projected to subsequently increase. As electricity prices increase, conventional electricity generators continue to approach the LCOE of PV systems, which drives PV technology towards grid-parity.[18]

Solar Photovoltaic Electricity Demand

Solar PV-generated electricity demand is primarily affected by the price elasticity of demand. Price elasticity of demand is a measure of how much the quantity demanded of a good or service fluctuates as a result of a change in price.[18] A good or service has an elastic demand if a small increase in price creates a large decrease in the quantity demanded. A good or service has an inelastic demand if a large increase in price creates a small decrease in the quantity demanded.[18] This effect also operates in the opposite manner as well. As with all goods, elasticity is largely dependent on the availability of close substitutes.[18] When solar PV-generated electricity is readily available, it can serve as a direct substitute for conventionally-generated electricity. This makes conventionally-generated electricity more elastic as an electric consumer could easily switch to PV-generated electricity to achieve the same outcome.[18] If a consumer has the preference of utilizing renewable power only, then her elasticity of PV electricity is relatively inelastic given the lack of close alternatives, which consist primarily of hydropower, wind, and geothermal resources that may not be as readily available as solar is in her particular locale. Otherwise, a consumer that has no renewable power preference will demonstrate very elastic PV electricity trends due to the large availability of close, conventional alternatives.[18]

Quantity of PV electricity demanded is also a function of energy constraint and response. In recent history, fuels have gone through periods of significant perceived accessibility and economic viability.[18] Fuel sources are inexpensive in these periods, which deteriorates the perceived need for alternative power sources such as solar PV; in these periods, the solar reserve is very small with the majority of solar resources falling under the subeconomic resource classification.[18] This ultimately decreases the quantity of PV electricity demanded due to inaccessibility. Fuel sources have also gone through periods of significant perceived inaccessibility (e.g. the oil crisis in the 1970s[1]) and economic infeasibility when conventional fuel prices are much more expensive than usual.[18] These times of energy constraint tend to solicit responses that spur governments to incentivize and expand alternative power sources such as PV.[18] It is during these periods that the solar reserve is large, and the quantity of PV electricity demanded is more due to greater accessibility.[18]

Quantifying Externalities via Government Incentives and Policies

Government incentives and policies surrounding solar PV energy are formulated by attempting to internalize externalities. An externality is a phenomenon that emerges as a result of a market transaction but is external to the decision of buying or selling the good/service.[18] While externalities can be positive or negative, renewable policies utilize negative externalities to create benefits for renewable energy. The most pertinent negative externality is created by conventional electricity generators that release significant amounts of CO_2 emissions into the atmosphere from combustion of fossil-fuels, namely coal and natural gas.[18] While this externality is created by a relatively small amount of entities, the cost of it is borne by many. This represents a detrimental market failure in the fossil-fuel power generation industry.[18]

To internalize this externality, governments impose policies to tax or obligate the entities so that their market activity reflects the cost of the relevant externality. In many renewable energy credit (REC) systems, entities contributing to large-scale pollution are legally obligated to purchase RECs to offset, or internalize, their pollution externality and simultaneously aide the renewable industry in meeting development costs.[24] Taxes collected from polluting entities may also be used to contribute to the funding of feed-in tariffs to support solar PV generation.[8] Policies such as these are pivotal in bridging the financial gap between the selling price of electricity and the LCOE of PV electricity generation that makes a solar resource economically viable and under the classifications of reserve or marginal reserve.

Application of the Solar Resource-Reserve Classification System

Having established the solar resource-reserve system, it can now be applied to the regional-dependent PV factors of the solar resource and reserve, and it can be further applied to India-specific resource-reserve factors. The solar resource is identified through analysis of the sun-earth relationship and climate factors in various regions. These factors are applied to the case of India. In the analysis of regional reserve factors, an economic analysis of the Indian electricity industry and its relation to utility-scale PV is provided to determine the capability of the solar resource to meet regional-based solar reserve classifications; this analysis details Indian electricity market pricing and government incentives that drive the economic viability of PV development. The resource-reserve method is applied to the specific case of a 5 MW PV system investment in India to determine feasibility of the development by quantifying the solar reserve. To account for all variables in the determination of economic viability, a financial analysis is used to calculate LCOE in comparison to the project's IRR and NPV from the cash inflows from electricity selling price and government incentives. Using the metrics for this specific case, the economic viability can be determined to interpret the quantities of solar resources and reserves to conclude feasibility of PV development in India.

Chapter 4

Regional Solar Resource Factors of Photovoltaic Energy Investment

Introduction to Regional Factors

The regional factors affecting solar energy PV investment pertain to solar energy as a resource and solar energy as a reserve. Different regions of the world will have a superior quality of solar irradiance, similar to how certain regions will have larger solar reserves due to regional economics that support PV development through government incentivizes. The regional factors that must be taken into account answer the question of where a PV utility-scale plant can be installed to successfully create a positive return on investment. The technical factors of solar PV energy investment (Chapter 2) pertain to the effectiveness of converting solar irradiance into electricity; whereas, regional factors entail the analysis of quality of irradiance to produce sufficient electricity and economics associated with regions to ensure the successful positive-return sale of generated electricity and renewable power. The regional solar resource factors include the sun-earth relationship, effect on irradiance, beneficial module orientation, and impacts from shading. While the technical factors covered in Chapter 2 affect all PV systems independent of location, these regional solar resource factors have positive characteristics specific to the Indian region.

The Sun-Earth Relationship

The placement and orientation of the sun and the earth ultimately effect the solar resource present in a specific location on the earth. The two astronomical movements that define the solar resource are earth's annual revolution around the sun and earth's 24 hour rotation about its axis.[25] Earth follows an almost elliptical orbit around the sun with a tilted axis of rotation.[25] The ecliptic plane is the plane intersecting the center of the earth and the center of the sun at every point in the earth's orbit, and the equatorial plane is the plane intersecting all points of the earth's equator.[25] The angle between the ecliptic and equatorial planes is equal to 23.45° and remains constant at every point of the earth's orbit.[25] Figure 7 provides a depiction of the ecliptic and equatorial planes.

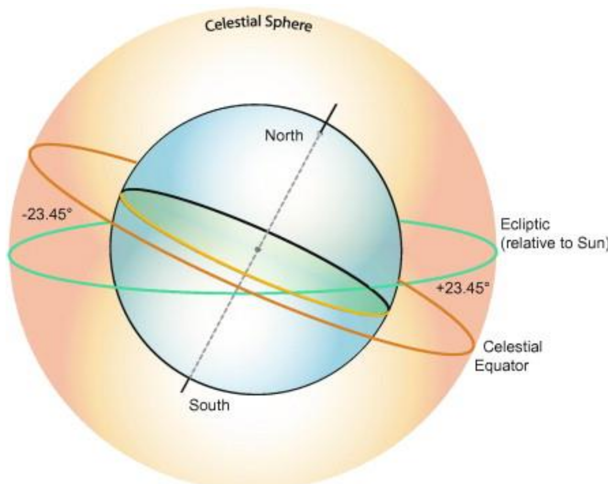

Figure 7: Ecliptic and Equatorial planes of the Earth[26]

While the angle between the ecliptic and equatorial planes shown in figure 7 remain constant throughout the earth's orbit, the angle between the equatorial plane and the rays of the sun does not remain constant.[25] This angle is referred to as the solar declination. In other words, the solar declination is the angle between the equator and the ecliptic plane resultant from the earth's tilt.[26] As the earth's axis remains at a tilted angle, the solar declination fluctuates continuously from -23.45° to +23.45° as the earth orbits the sun.[25] At any given point in the year, the location on the earth's surface where the sun is closest to receives the largest amount of solar energy, consequently raising the temperature of that region during that part of the year, which results in annual seasons. When the solar declination is a maximum of +23.45°, the Northern Hemisphere is closest to the sun's rays, and this time of year (around June 21st) is the summer solstice. Likewise, when the solar declination is a minimum of -23.45°, the Northern Hemisphere is farthest from the sun's rays while the Southern Hemisphere is the closest; this time of year (around December 21st) is the winter solstice.[25] As the solstices are the maximum and minimum points of the solar declination, the equinoxes are the points of the earth's orbit where solar declination is equal to 0°; the spring equinox occurs around March 21st, and the fall equinox occurs around September 23rd.[25]

The earth's rotation creates a movement of the sun—from the perspective of a terrestrial observer—across the sky throughout the day. The path of the sun is dependent on the latitude, time of day, and the time of year.[25] Latitude is used to express the geographic coordinate of a location in terms of the degrees north or south of the equator.[26] The sun's position in the sky relative to a terrestrial observer is defined by the solar altitude angle, which is the angle between the sun's central ray and a horizontal plane containing the observer.[25,26] The solar azimuth angle is used to define the sun's horizontal rotational position across the sky.[26] Figure 8 depicts the sun's position with angles relative to a terrestrial observer.

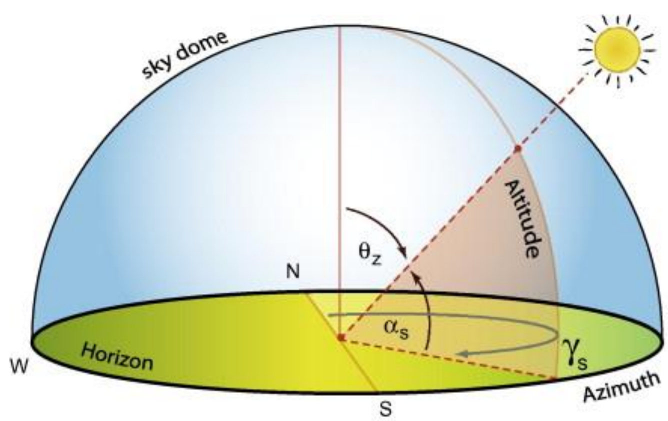

Figure 8: Sun Position Angles[26]

As figure 8 denotes, the solar altitude is typically denoted using α_s and solar azimuth is denoted using γ_s. The solar azimuth uses the north-south longitude along the horizontal plane as an angular reference.[26]

Over a year, the sun's position will vary in altitude depending on the latitude of the location. For Northern Hemisphere locations north of the tropic of cancer, the solar altitude is greatest during the summer solstice and is smallest during the winter solstice. During the equinoxes, the sun rises at an azimuth of due east and sets at an azimuth of due west.[25] These variations in the solar path create varying lengths of days. Because the solar altitude is greatest during the summer solstice, the sun's path has the greatest azimuth change from sunrise to sunset, making the summer solstice the longest day of the year. Conversely, the solar altitude is smallest during the winter solstice, giving the lowest azimuth change of the year and making the winter solstice the shortest day of the year. Figure 9 displays this annual sun path fluctuation.

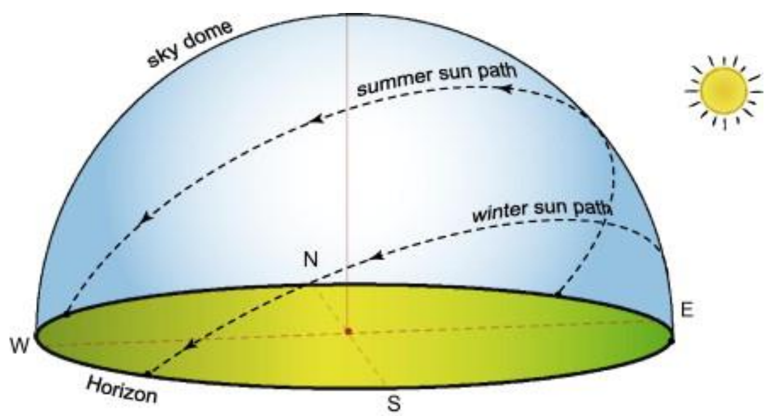

Figure 9: Annual fluctuation in sun paths[26]

Figure 9 depicts the degree of variation in sun paths over the year. If solar modules are not properly installed to account for this variation, significant amounts of the solar resource can be potentially lost. Additionally, changes in the sun path create different shading effects over the year. This is especially true when the sun is positioned lower in the sky, creating longer shadows that may cover portions of a solar array. Even minimal shading of a solar array can be detrimental to the power output of the overall system. For this reason, the rows of modules must also be placed at a far enough distance to prevent module rows from shading other module rows.

Professionally designed solar PV plants are developed to have extremely low to no shading throughout the year.

Solar Array Tilt, Azimuth, and Tracking

To account for the changes in solar angles throughout the year, solar modules are tilted at varying degrees to enhance the amount of the solar resource that is successfully converted. The ideal tilt angle of a module depends on the regional location of the PV system. The amount of solar energy that a PV cell receives can be adjusted by tilting the cell so that the maximum solar irradiance reaches the collector given the latitude of the location. In the case of clear weather, the sun's rays should be received by the PV cell at a 90° angle from the module plane, or a 0° angle of incidence, to maximize solar energy conversion. This can be described using figure 10.

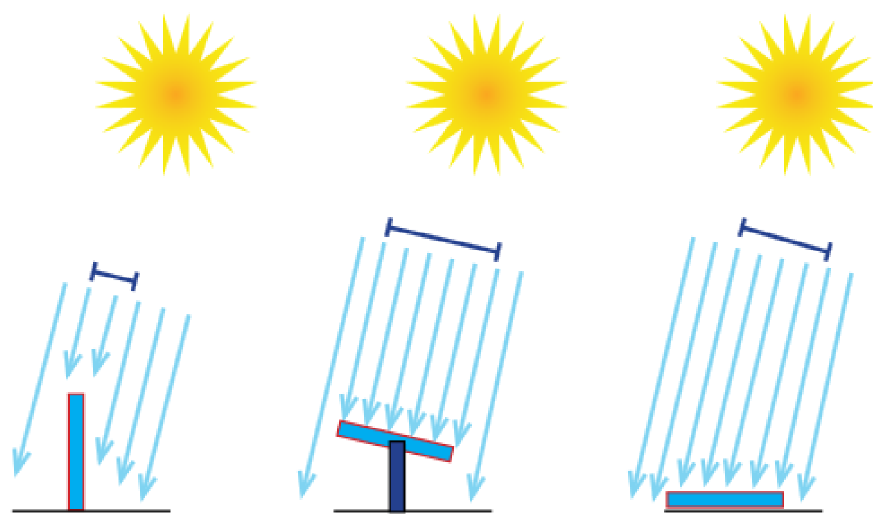

Figure 10: PV tilt angle[27]

As figure 10 displays, the optimal tilt angle for a PV cell exists at the angle where the solar rays can be received at a 0° angle of incidence (the middle image in figure 10). Otherwise (left and right images in figure 10), a smaller area of the PV cell is presented for the solar irradiance to be collected on, which reduces the overall solar energy the cell is capable of converting.[27]

Depending on the seasonal overcast tendencies of the PV system's location, the optimal fixed-tilt angle will maximize the resource conversion during optimum solar energy hours.[26] In locations that are subject to mostly clear days, the optimal tilt angle is the same exact angle as the latitude of the location.[25] In regions that tend to have cloudy seasons, the optimal angle is the one that has a 0° incident angle during the clearer season.[25] For example, southern locations tend to experience cloudy summer weather, which indicates that a larger tilt angle is beneficial to receive more solar energy during the winter seasons that tend to be clearer.[25] Some investors may also choose to create generation that is skewed for particular seasons; if the developer preferred to generate the most electricity during the summer season without minding a decrease in generation during the winter season, the solar array would be tilted less to take greater advantage of the high altitude sun during summer.[25]

Unlike the array tilt angle, which varies depending on the location, the fixed array azimuth always has a single direction to optimize solar resource conversion. For systems in the Northern Hemisphere, PV arrays generate the maximum amount of electricity when faced due south (and due north in the Southern Hemisphere).[25] However, PV systems that are meant to be mounted on top of an existing structure, such as a building's rooftop, may benefit by using an azimuth not facing due south. This is the case when structural mounting of the PV array to create a southern-facing azimuth is so costly that it drives the solar energy into a marginal reserve or subeconomic resource classification.[25] In most utility-scale PV systems, this issue is avoided as the solar modules are mounted specifically to achieve the optimal azimuth and tilt angle.

As opposed to fixed tilt and azimuth PV arrays, arrays can be installed with a tracking system that continuously changes the modules' orientation to track the sun's position with an almost 0° incident angle throughout the day. PV systems can have a single-axis tracker or a dual-axis tracker. Single-axis tracking follows the sun's position either by tracking its azimuth or by tracking its position across the sky from east to west.[25] Dual-axis tracking orients modules on two axes, which orients the modules to track the sun with a more exactly 0° incident angle.[25] Figure 11 depicts that this can increase annual solar power output by as much as 40%.[25]

Figure 11: PV tracking output gain[27]

Note that in figure 11, the non-tracking system experiences a power output maximum during the middle of the day, which is at solar noon. Solar noon is when the sun has its highest daily altitude and is directly south of the array; this is when the fixed array experiences a solar ray incident angle most near to 0°, and thus produces the most power. The tracking is able to increase the power output during much more of the day by increasing the time that the incident angle is near to 0°. This benefit must be analyzed in terms of the increase in solar reserves or marginal reserves from the solar resource; this can be quantified using LCOE calculations.

Solar Resource Irradiation Measurements

Solar resource measurements are utilized to determine the amount of electricity that can be produced via photovoltaic conversion. As discussed in the previous section, the solar resource varies by region due to the relative sun-earth relationship inherent to different locations. Additionally, the amount of solar resource that reaches the earth's surface depends largely on the amount of air mass the solar energy must travel through. Air mass is a measure of the thickness of atmosphere that solar energy must pass through.[25] As the sun's rays travel through air mass, solar energy is absorbed, scattered, and reflected by gases and particles present in the atmosphere (e.g. ozone, CO_2, water vapor, volcanic ash), reducing the amount of solar energy that reaches the surface.[25] Concurrently, the solar altitude directly affects the amount of air mass the solar resource must travel through to reach a location; when solar altitude is at its lowest, the relative air mass is at its maximum, and when the solar altitude is at its highest, the relative air mass is at its minimum.[25] Thus, the further the latitude is from the equator, the more significant the annual reductions in solar energy as a result of air mass will be.

The solar resource incident on the earth's surface is quantified in several difference ways. Solar irradiance is a measure of the power of solar radiation incident on a surface per unit area; it is expressed in kW/m^2 or W/m^2.[25] Solar irradiation is the amount of solar energy accumulated on a surface over a period of time; it is expressed in kWh/m^2 or Wh/m^2.[25] For evaluation of the solar resource at a specific location for a PV system, global horizontal irradiation, direct normal irradiation, and diffuse horizontal irradiation are typically used.[28]

Global horizontal irradiation (GHI) is the total amount of solar energy incident on a horizontal surface. GHI is inclusive of direct solar beam irradiation (DNI), diffuse radiation resulting from scattered light in the atmosphere (DHI), and scattered light from surroundings (e.g. ground reflectance).[28] PV power plants use GHI thoroughly to create electricity generation forecasts as PV plants are capable of converting both direct beam irradiation and diffuse irradiation.[28]

Direct normal irradiation (DNI) is the total solar energy incident on a surface that is facing the sun at all times.[28] DNI is particularly useful for PV power plants and concentrating solar technologies that track the sun and are intended to receive a significant amount of direct irradiation.[28]

Diffuse horizontal irradiation (DHI) is the total diffuse solar energy incident on a horizontal surface.[28] DHI is only inclusive of the light scattered in the atmosphere or from surrounding areas; it has no direct irradiation component.[28]

For specific and highly accurate measurements, the solar resource is measured at the ground site of a location where PV systems are expected to be installed in the future. Historical databases that contain solar irradiance data over long periods of time provide the most thorough measurements of solar resource.[25] Data over long periods of time assists PV developers in reducing uncertainty of the solar resource and providing long-term data with which they can compare their forecasted generation against their actual generation. Measurements at ground sites are typically taken using a pyranometer. Pyranometers are sensors that measure the GHI of the solar resource at a specific site.[25] These sensors are often mounted adjacent to a solar array, on the same plane as the array to provide the most accurate data.[25] The sensors are used in conjunction with data acquisition computers to measure the total GHI of the site at set intervals over periods of time.[25] Pyranometers are also utilized to measure the DHI of a site by using a shading plate to block all direct radiation from the sensor; this allows the sensor to measure all diffuse radiation from the atmosphere without capturing the direct component.[25] The DNI can be calculated by subtracting DHI from the GHI value measured by pyranometers, or it can be accurately measured directly using a pyrheliometer.[25] A pyrheliometer measures only the direct radiation in view of the disk; in order to obtain this measurement, the sensor disk must utilize a precise tracking system to be pointed normal to the sun’s rays throughout the day.[25]

If the measurements of the solar resource are not adequate, satellite solar irradiance data can be utilized instead. To create a library of accurate solar resource measurements in the form of regional solar atlases, ground sensors should be placed within 10 km of each other.[28] The solar resource determined by regional solar atlases that meet this 10 km requirement meet the classification of an identified resource. When solar resource values are assumed for a PV system using irradiance sensors that are not at the location the system, the developer assumes interpolation values of solar irradiation.[28] As the distance of the PV system from the sensors increases, uncertainty of the irradiance values also increases.[28] As uncertainty increases, the solar resource shifts from falling under the classification of an indicated resource to an inferred resource. If the perceived uncertainty of the solar resource becomes too great, a PV developer may choose to use data from satellite irradiance measurements.[28] Solar irradiance values derived from satellite measurements have been cross-examined with ground measurements and have been determined to provide reliable irradiation data for GHI measurements.[28] In the case of utility-scale PV, reliable GHI measurements from satellites place this quantification of the solar resource under the indicated resource classification. Variability of a location's solar resource poses a level of uncertainty for solar PV developers. The annual irradiation that a PV plant receives may vary from the average expected value as a result of natural annual climatic changes. However, the energy yield calculated by solar software over a long period of time (i.e. the life of the PV plant) is likely to be close to the average expected yield with an uncertainty of less than 10%.[28]

The Indian Solar Resource

India has solar irradiance data of different qualities.[28] Several cities, such as New Delhi, Mumbai, Chennai, and Sivaganga, have about 22 years of satellite-derived solar resource data from NASA.[28] Other sources utilize interpolation algorithms between ground sensors and satellite data to derive more accurate irradiation data for specific sites.[28] Figure 12 displays a map of average annual daily irradiation in India. Note that the Indian solar resource consists of annual average daily GHI ranging from about 4.75 to 6.00 kWh/m^2. The North-Eastern region of India is an exception and experiences much lower irradiation values. The overwhelming majority of India experiences GHI above 5.00 kWh/m^2 with a large portion of the central region having a GHI of over 5.25 kWh/m^2. These values are much higher daily GHIs than much of the US experiences.

In comparison, almost half of the US (the eastern regions) has GHI values of less than 4.5 kWh/m^2.[29]

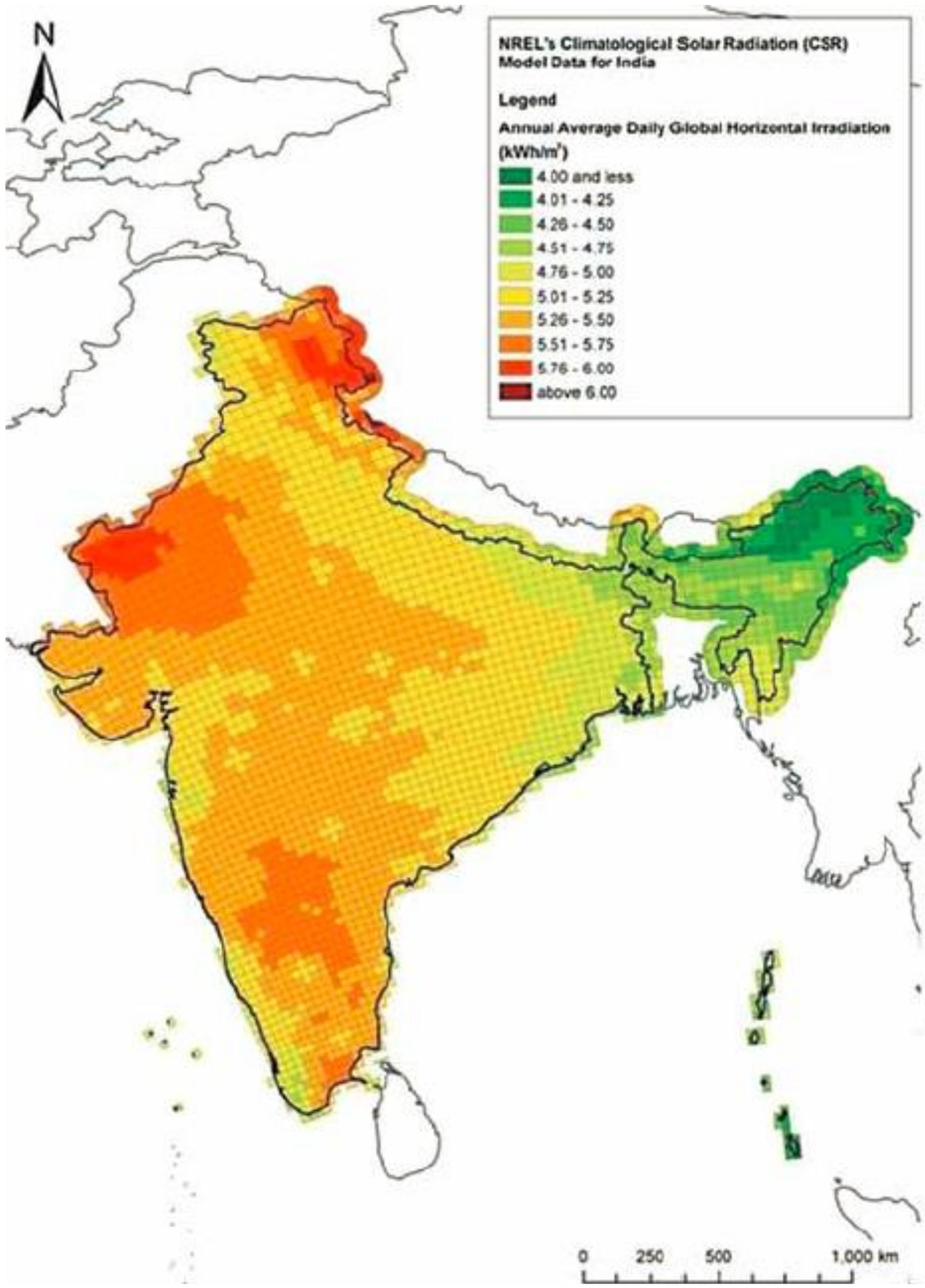

Figure 12: Indian solar GHI measurements[28]

The large solar resource values inherent to India are a result of the low Northern Hemisphere latitudes where the majority of India resides. As India is relatively close to the equator, the region experiences high solar altitudes throughout the year. These high altitudes minimize the air mass that the solar resource must travel through, which ultimately increases the solar resource incident on the region's land. As a result, modules installed in the southern regions of India require very low tilt angles.

While the solar resource includes all resource values in all regions, the portion of the solar resource pertinent to PV power plant developers is the solar resource intended to be collected by the plant. For example, if the solar power plant is intended to be placed in the central region of India, figure 12 displays that the PV system can be developed on a plot of land that experiences a GHI of about 5.50 kWh/m^2 daily. A large scale system can be designed to have a total land surface area of 5,000 m^2 with a PV module surface area of 2,000 m^2. This translates to a total daily average resource of 27,500 kWh incident on the land, consisting of a PV-collected solar irradiation of 11,000 kWh and a subeconomic resource of about 16,500 kWh that is incident on the 3,000 m^2 of land unused for PV conversion. Subeconomic resources would also result from angle of incidence losses, efficiency of conversion, and expected electrical losses in the solar resource conversion into electricity. Taken from satellite mapping resource data, these values would be further defined as an indicated solar resource. Depending on the economic factors of the PV plant, 100% of the solar resource converted into electricity would also be defined as a reserve, marginal reserve, or subeconomic resource. Alternatively, if a PV plant were installed on a plot of land in the North-Eastern region of India, the dedicated solar resource may entirely fall under subeconomic resource as the lower amount of convertible energy might fail to justify the cost of the system. This topic is covered for a specific example in chapter 6.

Chapter 5

Regional Solar Reserve Factors of Photovoltaic Energy Investment

As introduced in Chapter 3, solar PV reserve classifications pertain to the economic viability of converting the relevant solar resource into electricity via PV. From a regional standpoint, the economic viability is affected by electrical infrastructure, electricity prices, government incentives supporting PV, and cost-efficient access to PV materials. The Indian solar resource for PV is made economically viable with the capability of generating positive returns from the conversion of the solar resource. India has an environment conducive to driving a large portion of its solar resource into the classification of solar reserves and marginal reserves.

Indian Electrical Infrastructure

Without adequate electrical infrastructure, even an excellent solar resource (for the use of utility-scale PV systems) can be driven to a subeconomic resource. This can be described in terms of the cost of installing electrical infrastructure: if a PV system is to be installed in a location that does not have the electrical equipment (e.g. substation, transformers, high tension lines, etc.) to successfully distribute the generated electricity, the developer could theoretically internalize the cost to construct the electrical infrastructure to support the PV electricity distribution. This cost would, of course, be significantly expensive and would make the cash outflows to construct the PV plant much too large, subsequently driving the LCOE to a very high value. This, in turn, defines the solar resource of this location in the subeconomic resource classification, as the returns of the generated electricity could not possibly justify the overall cost of developing the plant. Therefore, an adequate electrical infrastructure must already be in place for a utility-scale PV plant to be economical and make a regional solar resource a reserve or marginal reserve.

Although suffering inefficiencies, the Indian grid provides adequate electrical infrastructure for grid connected solar PV systems as generators can effectively supply produced electricity into India's already established system of transmission and distribution networks. An electrical grid consists of generation, transmission, and distribution facilities. Generators are the producers of electricity and consist of coal, gas, nuclear, and renewable (e.g. solar PV) power plants. Generators send the electricity to transmission facilities, which step up the electric voltage to be carried by high-voltage wires to load centers.[30] The load centers then send the electricity to distribution facilities, which step down the voltage to be distributed to the end-user of electricity. The Indian grid is divided into 5 different electrical regions: Northern, Northeastern, Eastern, Western, and Southern.[30] Figure 13 depicts these electrical regions over the map of India.

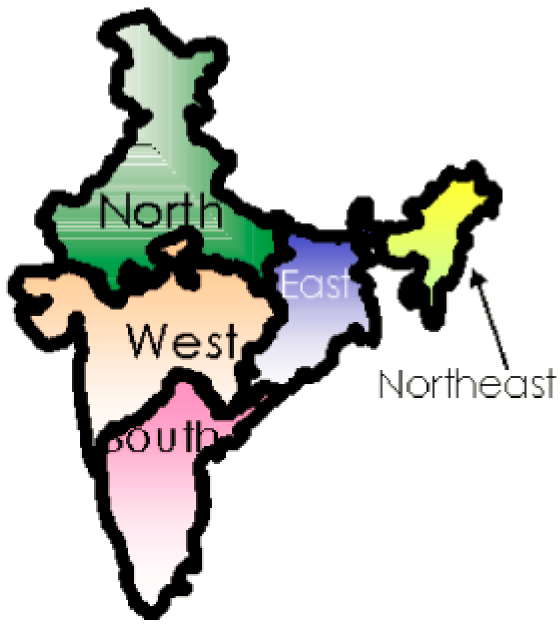

Figure 13: Indian electrical grid regions[30]

The electricity produced by the generators is transmitted to a Regional Load Dispatch Center (RLDC); each of the 5 regions shown in figure 13 has a single RLDC.[30] The RLDCs coordinate the use of the transmission systems within the region. In addition, each state has a State Load Dispatch Center (SLDC) that coordinates electrical transmission usage within the state and reports its data to its respective RLDC.[30] As of 2014, all five regions of the electrical grid operate synchronously with power flowing seamlessly across all regions; prior to 2014, all transmission regions were interconnected but the southern region, creating a portion of the grid that operated asynchronously.[31]

Generation and transmission of electricity is scheduled through the use of open access contracts.[30] Open access contracts provide access to a certain amount of transmission capacity as specified by the contract as long as the grid is operating reliably.[30] Generators have long-term (12+ years), medium-term (3 months to 3 years), or short-term (monthly to 4 month maximum) open-access contracts.[30] In the event of transmission congestion, short-term contract generator transmissions are decreased first, followed by medium-term contract generators, and then by long-term contract generators.[30] As such, long-term contracts are the most expensive, while short-term contracts are the least expensive.[30] The SLDCs coordinate the contract-based expected transmissions by day-ahead scheduling each day into 96 time blocks of 15 minutes.[30] The SLDCs monitor actual generator injection and electricity extraction by state utilities to compare the actual transmissions with respect to the scheduled transmissions.[30] The deviations from the scheduled transmission are relayed to the RLDCs and priced using the Unscheduled Interchange (UI) rate.[30] When state utilities extract more electricity than scheduled, they pay the higher UI rate; likewise, when generators transmit more electricity than scheduled (assuming normal grid operation), they are compensated at the higher UI rate.[30]

From an electrical standpoint, the grid operates at several different voltages to efficiently transmit electricity. Generators typically produce electricity at a voltage of 11kV to 25kV.[32] Major generators that produce significant sums of electricity will feed into substations that utilize transformers to step up the electricity to voltages of 400 kV, 220 kV, or 132 kV, while smaller generators feed into substations that step up electricity to voltages of 66 kV, 33 kV, or 11kV.[33] The electricity is stepped up to higher voltages in order to transmit the electricity via high voltage lines across great distances—usually hundreds of kilometers—with minimal electrical loss.[32] After being stepped up, the electricity is fed into the relative RLDCs where the electricity is dispatched to a sub-transmission network at a stepped-down voltage of 66 kV or 33 kV, depending on the region.[32] These lines terminate at 33 kV substations, which further step down the electricity to 11 kV for distribution. The 11 kV transmission network distributes the electricity to areas in close proximity to load centers, such as buildings, villages, and towns, where transformers reduce the voltage to 415 kV for the last mile stretch to individual end-users.[32]

The Indian electrical grid suffers from frequent outages and failures due to over demand and inadequate grid monitoring. The Indian electrical grid is intended to operate between 49.0 and 50.5 Hz with a delivery voltage of 220-240 V.[30] If the transmission networks experience any irregular frequencies, circuit breakers in various substations can open automatically as a safety measure against faults.[32] Irregular frequencies can be a result of overloading or, more frequently, excess electrical demand. Rather than isolating specific portions of the 11 kV distribution network to disconnect, the 33 kV substations typically offer the furthest downstream switch in the grid.[32] Therefore, when an irregular frequency is experienced, the 33 kV circuit breaker is tripped, which shuts off all electrical transmission to entire networks of 11 kV sub-networks. These networks represent very large portions of end-users that are left without power when a circuit breaker is opened.[32] This issue is largely related to lack of adequate grid monitoring and lack of generators to meet demand. To help meet electrical demand, additions in the form of PV generation can benefit the Indian electrical grid. India, therefore, meets the requirement of providing an adequate electrical grid for PV power distribution, which assists in generating solar reserves from the abundant solar resource.

Indian Electricity Market

Electricity prices in the Indian market greatly affect the potential revenue stream for PV plants. Because many PV plants sell electricity to an end-user, the PV plants must compete against the local electricity market rate to negotiate a PV-generated electricity price with the end user. Therefore, the sale price of PV-generated electricity must exist at a rate competitive to the price of other electricity purchasing opportunities. However, the Indian electricity market has prices that vary by region, consumer type, and a host of other factors. By investigating the Indian electricity market prices, the factors that in turn affect the electricity rates for large scale PV systems can also be determined. These electricity rates determine the cost justification for solar resource conversion, which in turn determines the solar reserve classification of the resource. The key components affecting Indian electricity prices are electricity sale policies and operations, fuel costs, regional supply, and demand trends.

Electricity generators are split into power plants that are owned by the central government of India, the state government, and by private entities (Independent Power Producers). As shown in figure 14, the central government of India owns approximately 28% of total installed generation capacity, the state governments own approximately 39%, and the private sector owns approximately 33%.[34] These installed capacities differ by power plant type, as depicted by figure 15.

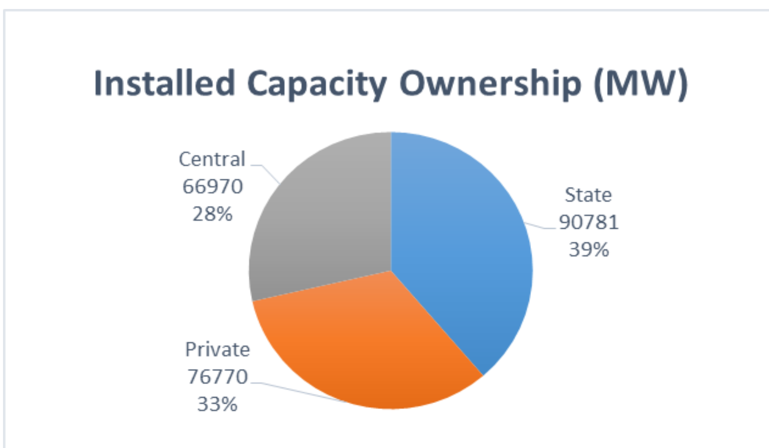

Figure 14: Ownership distribution of installed generation capacity in India[34]

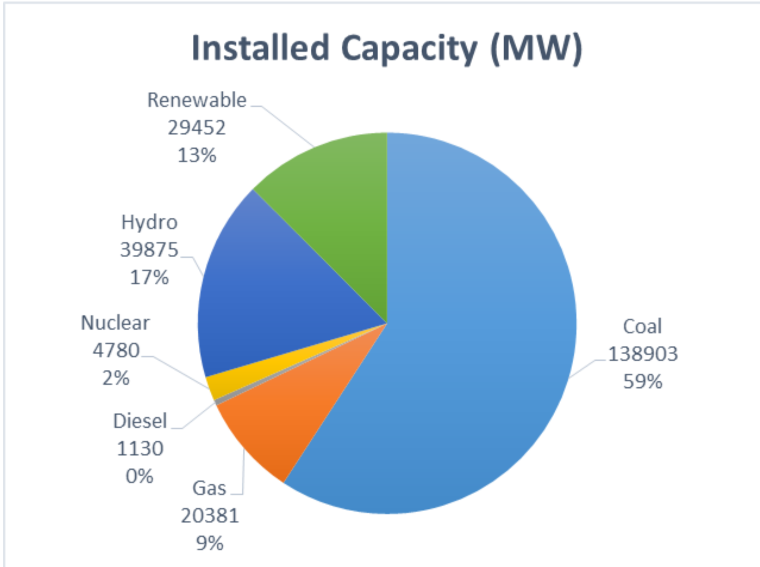

Figure 15: Installed generation capacity by type in India[34]

Coal-fired thermal power plants represent the majority of power generation in India at 59% of total generation. At 17%, hydropower is the next largest source of power generation in India, followed by renewables at 13%. Note that the majority of renewables is owned by the private power generation sector; likewise, the private sector owns slightly less than half of the coal power generation. The central government owns 100% of nuclear capacity and majority shares in coal and gas ownership; whereas, the state governments owns the overwhelming majority of hydropower generation. Diesel generation consists primarily of small scale grid connected generators.

The four wholesale mechanisms by which electricity is traded from these generators are via long-term contracts, short-term bilateral contracts, unscheduled interchange (UI), and power exchanges.[35] Long-term contracts (discussed in previous section) are made between the generators and distribution companies, known as Discoms, or State Electricity Boards (SEBs).[35] The Discoms/SEBs are responsible for providing electricity to the end-consumer. The overwhelming majority of end-user electricity supply is intended to be fulfilled by the Discom/SEB's long-term contracts.[35] Short-term bilateral contracts are typically utilized for inter-state or inter-regional electricity trading by Central Electricity Regulatory Commission (CERC) certified traders.[35] These short-term contracts are necessary when a state or electrical region must import electricity from generators in other states or other electrical regions due to high demand or generator excess output. As the long-term and short-term contracts are scheduled on a day-ahead basis, the difference between scheduled generation and actual generation is charged at the higher UI rate (discussed in the previous section).[35] Lastly, electricity is purchased via the power exchanges, which utilize double-sided closed auction bidding for day-ahead delivery.[35] This auction process enables price discovery whereby suppliers and buyers receive/pay the same uniform price of electricity. Power exchanges are intended to cover small portions of overall energy demand.[35] After long-term contracts, electricity is transferred in the largest quantities via short-term contracts, the UI rate, and power exchanges, respectively. For example, in September of 2009, approximately 91.15% of electricity was sold via long-term contracts, 4.52% was sold through short-term bilateral contracts, 3.50% was sold via the UI rate, and 0.83% was sold via the power exchanges.[35]

These wholesale mechanisms use specific rates to transfer the costs and consumption rights from the generators to the end-user. The Electricity Act of 2003 was enacted to increase competition amongst generators and established the Availability Based Tariff (ABT).[35] The ABT defines the rates used for the purchasing of bulk electricity from all central government owned generators in the wholesale market; additionally, most state-owned generators have adopted the use of ABT rates in power purchasing.[36] The ABT consists of three tiers of rates that allocate prices based on fixed costs, variable costs, and current electrical demand (i.e. “availability”).[36] The first component of the ABT is the fixed charge, or capacity charge, which is a rate payable every month by the beneficiary (i.e. the receiver of electricity) to the generator in return for the use of the generator’s generation capacity. Beneficiaries make fixed charge payments proportional to the share of the generator’s capacity (in MW) that they utilize.[36] The fixed charge meets the generator's fixed costs, which consist of loan interest expenses, return on equity, depreciation, operation and maintenance, insurance, and interest on working capital.[36] The second component of the ABT is the energy charge, which is the per kWh rate charged to the beneficiaries in exchange for the generator's supply of electricity in accordance with the day-ahead schedule.[36] The energy charge is used to justify the generator's variable cost, such as fuel costs for coal and gas plants, or Uranium for nuclear plants.[36] The final component of the ABT is the UI rate, which addresses the payment rate for variations in the day-ahead schedule. In order to incentivize a grid operation frequency of 50 Hz, which optimizes grid performance and reduces the risk of faults, the UI rate is larger when the frequency is below 50 Hz (to incentivize higher output during high demand hours) and is less when the frequency is above 50 Hz (to disincentivize output during high supply/low demand hours).[36]

To provide an example of ABT, assume a central-owned gas-fired power plant has an average output capacity of 2000 MW and has 4 Discoms beneficiaries (A,B,C, and D) that have 35%, 30%, 25%, and 10% capacity share of the plant, respectively. Each Discom plans to utilize their respective capacity share for the full 24 hours of the day. Discoms A, B, C, and D have 700 MW, 500 MW, 400 MW, and 200 MW shares, respectively, and pay the proportional fixed charge to the generator to cover the plant's entire fixed cost allocation. Their variable energy charges are applied for 16,800 MWh (*700 MW x 24 hrs*), 12,000 MWh, 9,600 MWh, and 4,800 MWh, respectively, at the specified energy charge rate for the gas-fired generator.[36]

The ABT or PPA rates are used in conjunction with the contracts to price electricity to the end-user. Long-term contracts made between Discoms/SEBs and central-owned/state-owned generators use the ABT cost-based rates to price electricity; whereas, privately owned generators (IPPs) create their own bilateral long-term or short-term contracts with Discoms/SEBs that establish separate electricity rates based on their power purchase agreement (PPA).[35] Alternatively, IPPs can enter into bilateral contracts directly with large end-users (e.g. factories, warehouses, offices, etc.), which is often the case in large-scale PV development. The Discoms/SEBs, which also acquire electricity through short-term contracts, the UI, and power exchanges, then utilize their energy portfolios to adequately price and distribute electricity to the end-user.[35] India enacts central and state policies that allow for significant cross-subsidization of end-users; commercial and industrial electricity consumers are typically subject to much higher electricity tariffs than domestic end-users and Indian farmers.[37]

The generation portfolio of India (figure 15) greatly affects end-user electricity prices as a result of fuel costs. Approximately 30% of India's generation capacity is from hydropower and renewable, while the remaining 70% requires fuel for operation.[34] Given the variable cost component of ABT intended to cover fuel costs of generators, cost of fuel directly affects the electricity rates that Discoms/SEBs pay to generators, which in turn affects the end-user price of electricity. Likewise, IPPs will seek to internalize their expected fuel costs in their PPA prices charged to the respective Discoms/SEBs. Because each SEB and Discom establishes a portfolio of energy generators to set its prices, fuel costs of the generators will affect end-user electricity prices. Coal and natural gas generators are the major fuel-consuming plants that make up 59% and 9% of India's installed generation, respectively; therefore, coal and natural gas fuel prices determine the energy rate component of the Indian ABT for fuel-consuming generators. The CERC adjusts the energy charge component of the ABT to account for variable changes in the coal and natural gas fuel prices; when fuel prices rise or fall, the respective ABT energy charges for the type of plant increase or decrease accordingly to meet the higher generation costs.[36] While SEBs/Discoms are able to hedge against fuel cost risks with long-term IPP contracts that specify future negotiated rates, the ABT energy charge removes that capability for contracts with government-owned plants. As such, fuel costs have the most significant effect on end-user rates.[35]

Electricity Supply and Demand in India

Along with fuel pricing, the differences in supply and demand in the five electrical regions creates significant regional electricity pricing pressures. As hydropower accounts for 17% of electricity generation, a large portion of regional electricity supply is dependent on the seasonal fluctuations affecting hydropower reservoir feeds.[35] The five electrical regions consist of generation capacities that supply amounts of electricity that do not always match the demanded electrical load. This creates a need for exporting and importing of electricity via inter-state or inter-regional transmission networks. Figure 16 displays the major supply and demand factors affecting the five electrical regions.

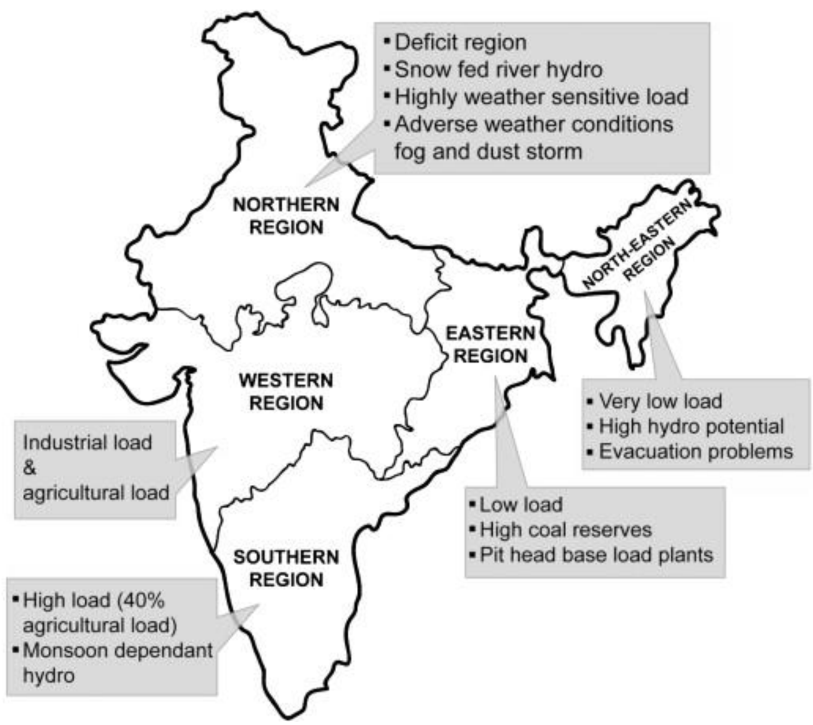

Figure 16: Supply and demand factors in five Indian electrical regions[35]

While the north-eastern region has untapped hydropower potential, the northern and southern regions have hydropower generation dependent on snow feed and monsoons, respectively. Each region experiences variable electrical load demand with the northern region the most sensitive to weather, the western and southern regions the highest demand, and eastern and north-eastern regions the lowest demand.[35] When high-generating regions wish to export to high-load regions, transmission of electricity between states and regions experiences congestion and technical constraints that cause bottlenecks during periods of high-volume inter-regional trading.[35] Congestion bottlenecks are most frequently experienced for electricity transmission between eastern-western regions and eastern-northern regions as a result of high excess generation in the eastern region that is exported to other seasonally high-demand regions.[35] A common case occurs during the summertime when load demand is very high in the northern region, and transmission capacity is not able to import electricity from higher generating eastern and north-eastern regions to meet demand.[35] In cases such as these, the domestic regional generators in the deficit region have significant market power and are able to price electricity at much higher rates, which puts upward price pressure on end-user electricity rates.[35]

Each of the five electrical regions are subject to significant annual energy deficits, which exacerbate at specific high-load times of the year. Table 1 displays the annual energy demand, supply, deficit, and months when peak load is experienced.

Table 1: India energy deficits by region (2008-2009)[35]

Region	Annual energy demand	Annual energy supply	Energy deficit	Months of peak load
Northern	224,218 GWh	199,928 GWh	10.83 %	Jun, Jul, Aug
Western	254,486 GWh	213,724 GWh	16.02%	Dec
Southern	204,086 GWh	188,865 GWh	7.46%	Mar, Oct
Eastern	82,127 GWh	78,370 GWh	4.57%	Mar
North-eastern	9,407 GWh	8,134 GWh	13.53%	Jan
All India	774,324 GWh	689,021 GWh	11.02%	Mar, Oct

As table 1 depicts, the western region experiences the largest energy deficit of 16.02% as it demands the most electricity, while the eastern region experiences the smallest deficit of 4.57% due to its high proportional generation capability. Because the eastern region experiences its peak load in the month of March only, it is able to export electricity to the northern and western regions during their peak loads in June, July, August, and December. Note that every region experiences an energy deficit, which gives India a cumulative deficit of 11.02% with overall peak loads in March and October.[35] This overall energy deficit was calculated using the difference in energy supply and demand with respect to the total energy demanded; this analysis identified that the largest overall energy deficits were experienced in the months of March and October.[35] Because of this deficit, there is a need to install additional generating capacity in all regions of India. As deficits persist, the UI rate component increases the overall price of electricity from central and state owned generators. As a result, this gap that exists between electrical demand and supply is an important factor in driving electricity prices higher.[35]

Electricity Prices in India

Indian electricity prices have followed an increasing trend and continue to do so in both domestic end-user and non-domestic end-user consumption. Increases in fuel costs and a continuing energy deficit create upward pressure on end-user electricity prices (referred to as "tariffs"). Non-domestic end-users (i.e. industrial and commercial) have experienced as high as 34% increases in electricity rates, with an average increase of 13.4% in 2013.[38] The average non-domestic electricity rate in India is about Rs. 5.97 per kWh, which is equivalent to about $0.10 per kWh (review Appendix B for Indian currency details).[38] Domestic (i.e. residential) end-user electricity rates have also followed increasing trends, with increases as much as 28%.[38] The average increase in domestic Indian rates was about 16.5% in 2013, with an average rate of about Rs. 4.99 per kWh, which is equivalent to about $0.08 per kWh.[38] As generation capacity continues to increase in India, so does energy demand, which allows for a continuing energy deficit. Given this prominent deficit and current increasing price trends, India's electricity rates are expected to continue rising at over 10% per year.[38]

Increasing electricity prices in India ultimately increases the amount and value of solar reserves for large-scale PV systems. Large-scale solar PV has not reached grid parity with respect to other generators in most countries. When PV systems are able to generate electricity at a financially sustainable level without the need for subsidization, these systems reach grid-parity. In order to reach financial sustainability, the revenue stream of the system must justify the costs of the system; as chapter 3 discussed, a PV project is economically viable when its cash inflows are greater than its cash outflows. These can be marginally compared using levelized revenue of electricity (LROE in $/kWh) against LCOE of the project. As the cost of PV materials continues to decrease, large-scale PV approaches competitive grid-parity. PV grid parity in India is set on a faster pace as the market price of electricity continues to increase at a fast pace; these increasing prices will allow PV project LROE to surpass PV LCOE before other regions of the world that have lower electricity prices. As this enhances the economic viability of large-scale PV generators, more of the Indian solar resource is able to be classified as solar reserves. The amount of Indian solar reserves will continue to increase as electricity prices increase and PV LCOE decreases.

Introduction to Solar Photovoltaic Financial Benefits

Amongst the renewable energy policies enacted by governments around the world, feed-in tariff (FIT) and renewable portfolio standard (RPS) policies are the most prominent.[8] FITs are typically used to promote renewable technology by offering long-term (15-20 year) contracts that establish a beneficial price of electricity for the generator. The electricity pricing of FITs typically depends on the cost of the generation technology and project size. Renewable energy projects, such as large-scale PV, require FITs in order to justify their inherent higher capital and operating costs, which the market electricity rates are incapable of accomplishing. This allows large-scale PV, which has not reached grid-parity in most parts of the world, to be capable of competing with lower-cost conventional generators. Under this scheme, renewable electricity is purchased by large utilities at the specified FIT rate who then bundle the higher cost electricity with large quantities of lower cost conventional electricity to create an overall lower average price.[8]

There are four common methods of calculating FIT rates. Utilized widely in the European Union, FIT rates can be calculated by using the LCOE of the type of generation; this method typically defines a rate that meets the LCOE with an additional policy-set rate of return.[8] The FIT can also be determined using the inherent value to society or the utility based on avoided costs (e.g. avoided cost of fuel).[8] Alternatively, the FIT can be set as a fixed-price independent of LCOE or avoided costs.[8] As is the case in certain Indian policies, the FIT can be determined by an auction or bidding process, which allows market participants to assist in price discovery.[8] The most widely used, and most economical, FIT calculation methods are those which interpret generator costs.[8] FITs have the benefit of providing a stable, low risk, pricing scheme allowing enhanced revenue forecasting, which facilitates generator project financing.[8]

Renewable portfolio standards are an alternative method to FITs that create power purchasing requirements for large utilities. RPS require bulk electricity suppliers to provide a policy-specified portion of electricity from renewable sources.[8] While suppliers are able to meet their renewable target by direct purchasing of electricity from renewable generators, it is often more practical and economical for RPS obligations to be met via renewable energy credits (RECs). RECs are created for each unit of electricity (typically 1 MWh per REC) generated by a renewable generator. The RECs can then be traded on an open marketplace, where suppliers can purchase the credits to meet their RPS targets.[8] The sale of RECs provides a supplementary source of income for renewable generators, which enhances generator competitiveness while facilitating supply of renewable electricity rights.[8] Utilizing RECs to justify projects costs increases developer risk as RECs are subject to price volatility. This makes revenue projection variable, which can create project financing difficulty.[8]

FIT, RPS, and other renewable energy policies are essential to increasing large-scale solar PV reserves. Additional policies to support PV consist of various tax breaks and beneficial project accounting procedures.[39] The single most prevailing issue hindering solar PV development is procuring an economical rate of return. Rate of return on large-scale solar PV is inherently difficult due to large capital costs.[39] FITs and RPS policies assist in creating economical rate of returns and drive project economic viability. These policies allows more of the solar PV resource to be economically convertible, creating an increase in solar PV reserves.

Indian Solar Photovoltaic Financial Incentive Analysis

Large-scale PV in India is supported by the Jawaharlal Nehru National Solar Mission (NSM), CERC Regulations on FITs and RECs, and individual state policies.[39] The NSM plans to achieve a total installed solar PV (grid-tied) capacity of 20,000 MW by the year 2022; it consists of three phases with targeted deployment of 1,000 MW by 2013, 10,000 MW by 2017, and 20,000 MW by 2022.[40] The CERC regulation policies on FITs and RECs act as promoters of the NSM by providing the foundation for these mechanisms' terms and conditions to meet the NSM targets. Additionally, the state-government-imposed policies provide mechanisms for the State Electricity Regulatory Commissions (SERCs) to enable compliance with the NSM.

The NSM aims to achieve its targets by imposing renewable purchase obligations (RPOs) at the state level. RPOs follow the general RPS policy strategy discussed in the previous section. Electricity suppliers in India (i.e. Discoms/SEBs) have an average RPO of 5%, of which 0.25% must be met specifically by solar-generated electricity.[41] The solar RPO portion is to be increased through 2022 to further enhance solar PV deployment.[40] RPOs can be met by FITs and RECs.[41] FITs allows the direct purchasing of electricity from generators, while RECs allow the purchasing of the renewable electricity rights; while FITs are awarded to generators that deliver electricity directly to the Discom/SEB's distribution network, RECs can be traded from any generator location in India.[41] This is especially beneficial for states that may not have adequate solar PV generators but still remain subject to a state RPO.[40]

FITs, referred to as preferential tariffs in Indian policy, are set at the state level using different calculation methods. Certain Indian states, such as Gujarat, offer a two phase cost-based

FIT to solar PV generators, with Rs. 15/kWh for the first 12 years, followed by Rs. 5/kWh for 13 years.[41] Many other states, such as Karnataka and Madhya Pradesh, offer FITs using reverse-bidding auction mechanisms.[41] Under the reverse-bidding process, potential solar developers bid for solar PV grid connection by offering tariffs, where the lowest bid tariff is allocated the connection rights. In Karnataka, the highest FIT awarded was 8.50/kWh, and the lowest FIT awarded was Rs. 7.94/kWh.[41] Madhya Pradesh allocated FITs that ranged between Rs. 7.90 to 8.05/kWh.[41] The FIT rates are much higher than rates paid to non-renewable generators, which allows justification of the high capital costs of solar PV.

It is important to note that certain state governments, such as Andhra Pradesh, have threatened the entire legitimacy of solar PV FIT allocation in India. Reverse bidding auctions are typically awarded at individual substations. If a substation can receive an electrical input of 20 MW, an FIT will be awarded to the developer(s) that bid for the 20 MWs of input specific to the substation; therefore, FITs awarded at one substation in a state are not intended to affect FITs allocated at other substations within the same state. Andhra Pradesh imposed a policy using this mechanism to meet their RPO. However, after Sunborne Energy bid a low tariff of Rs. 6.49/kWh at a single substation in Andhra Pradesh, the state government negated its previous substation-dependent policy and imposed the low Rs. 6.49/kWh FIT for all solar developers in the state. This new FIT was made applicable even to solar developers that had already been awarded higher FIT rates at other substations. All solar developers in Andhra Pradesh, including Sunborne Energy, have since then deemed this FIT rate uneconomical, which has halted all solar PV development in the state that had initially intended to utilize the FIT mechanism. This exemplifies the inherent weakness of the reverse bidding process for FIT discovery and reveals Indian state governments' willingness to renege on imposed policies, adding a significant layer of price risk.[42,43]

Alternative to the FIT method, solar PV generated electricity can be sold using REC mechanisms to justify high developer costs (note that a generator must choose the FIT mechanism

OR the REC mechanism, not both). Sale of RECs is a supplementary benefit to solar PV developers in addition to the base sale of electricity.[41] Under this mechanism, a solar PV developer can choose to sell electricity directly to the utilities at the Average Pooled in Power Cost (APPC), which ranges from Rs. 2 to Rs. 3/kWh.[41] Otherwise, the developer can sell the electricity to a 3rd party end-user via a PPA, which specifies electricity rates, terms, and conditions.[41] Sale to a third party end-user is generally the preferred method as 3rd party PPAs specify rates close in value to Indian electricity market rates, which are much higher than the APPC. While the developer sells electricity to the grid or a 3rd party, the developer also receives RECs for every 1,000 kWh of generation delivered to the grid.[41]

The price of RECs varies according to supply and demand market forces and CERC price regulations. RECs are traded over the power exchanges for one day on the last Wednesday of every month.[44] Under the CERC policy imposing the use of RECs for RPOs, the price of RECs is regulated by a floor and forbearance (i.e. ceiling) price; the REC floor and forbearance prices are Rs. 9,300 and Rs. 13,400 per REC, respectively.[41] This translates to a price of Rs. 9.3 and Rs. 13.4 per kWh of solar PV generated electricity. Figure 17 depicts a graph of REC prices from May, 2012 (the first month of solar REC trading) to February, 2014 with black dashed lines to indicate the floor and forbearance price.

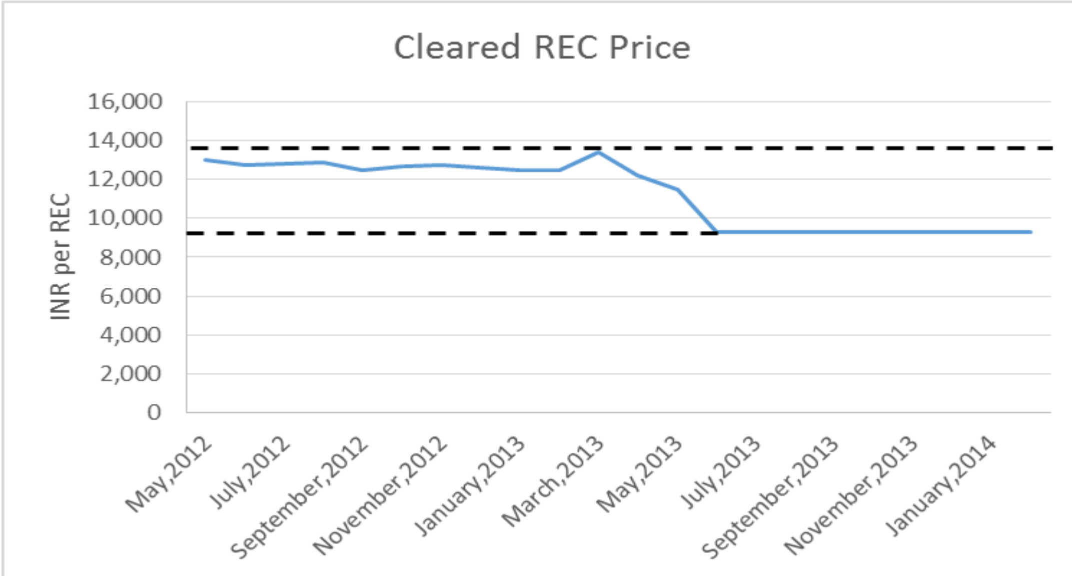

Figure 17: India solar REC price history with graphed floor and ceiling prices[44]

RECs began trading at Rs. 13,000 and fluctuated between Rs. 12,850 and Rs. 12,500 through February, 2013.[44] Trading only ever reached the REC forbearance price of Rs. 13,400 once during March, 2013.[44] Thereafter, the price steadily dropped to the floor price of Rs. 9,300 during June, 2013, where it has remained since then.[44] The price of RECs is set by the sell and buy bids within the REC marketplace on the Indian power exchanges. From May, 2012 to April, 2013, the buy bids outnumbered the sell bids usually by about 1,000 bids. For example, there were 5,238 buy bids and 3,192 sell bids during March, 2013 trading; the greater demand (buy bids) for RECs than REC supply (sell bids) kept upward REC price pressure as sellers could demand higher REC prices.[44] However, sell bids began to greatly outpace buy bids after May, 2013. This issue has continued to escalate to present day. During February, 2013 REC trading, there were 114,539 sell bids and only 7,816 buy bids.[44] As the supply of RECs has grown much greater than demanded RECs, many sellers are willing to sell at the floor price of Rs. 9,300. Since June, 2013, the number of cleared RECs has been equivalent to the number of buy bids, all of which have been at the floor price.

Lack of RPO enforcement has caused a severe REC market clearance issue that exacerbates REC mechanism revenue risk. In order for obligated entities to meet their RPOs, enforcement measures must be taken to ensure that state RPOs are met. While the CERC has encouraged solar RPO enforcement at the SERCs, enforcement measures at the state level were not well defined, if at all, prior to August, 2013.[45] Many states were capable of simply not meeting RPOs without any consequence whatsoever. SERCs, such as in Gujarat and Punjab, allowed Discoms to carry forward shortfalls in RPOs to the following years at no penalty.[45] Additionally, the Gujarat SERC later nullified the entire state Discoms' RPO shortfalls deeming that meeting the RPOs by purchasing of RECs would be impractical.[45] After Discoms/SEBs discovered the lack of enforcement, REC purchasing plummeted. This effect is depicted by the graph of issued and redeemed RECs in figure 18.

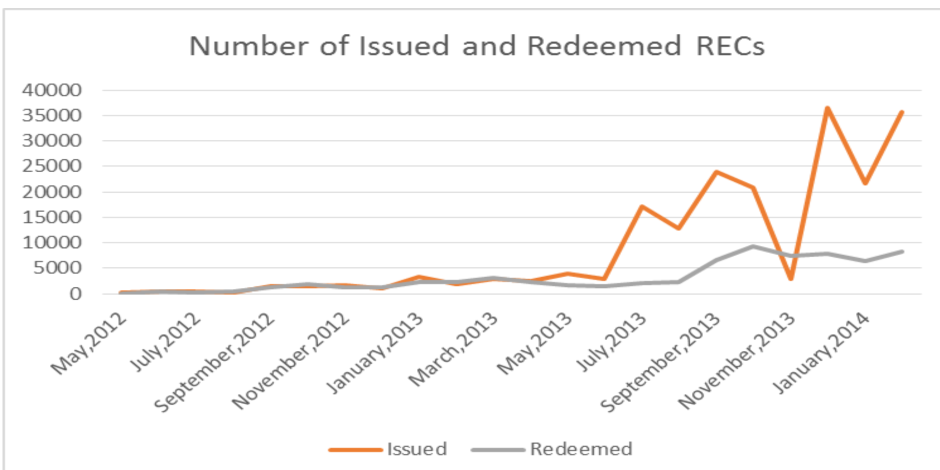

Figure 18: Number of issued and redeemed (purchased) Indian solar RECs[46]

Note that in figure 18 solar RECs are issued as solar PV generators feed 1 MWh into the grid and submit their generation data to their respective agency, and these RECs remain valid for 2 years after issuance; RECs are redeemed when they are purchased by obligated entities.[46] Figure 18 shows that as RECs first became traded, Discoms initially complied with the RPOs and purchased almost 100% of issued RECs through the start of 2013.[46] After March, 2013, lack of RPO enforcement created a significant decrease in redeemed RECs. This lack of REC demand coupled with high REC issuance from new solar generators created an oversupply placing strong downward price pressure on RECs, driving them to the floor price.

After August, 2013, SERCs began to scale up RPO enforcement initiatives, which aided in the redeeming of RECs but has not made an impact on the large quantity of outstanding RECs. The SERCs of Punjab, Maharashtra, Madhya Pradesh, and Delhi have made strides to increase compliance of cumulative RPOs.[45] Several of these states have launched compliance penalty regulations, which will charge the obligated entities Rs. 13,400 per MWh (equal to the REC forbearance price) of RPO noncompliance by March, 2014.[45] This strongly incentivized obligated entities to purchase RECs, which typically trade at a price lower than the noncompliance penalty; this effect can be seen in figure 18 as redeemed RECs moved much higher after August, 2013.[46] However, the lack of compliance in previous years has left a significant amount of RECs on the market, exacerbating the oversupply issue. This is depicted in figure 19. The RECs that were not purchased previously has left a supply of about 126,138 RECs on the market.[46] As old generators continue to issue RECs and new generators come online, the number of RECs will continue to grow and outpace REC demand. It is crucial that SERCs enforce noncompliance of previous year RPOs to assist in clearing the REC market of its oversupply. The Indian REC market may not have been subject to such drastic oversupply if a floor price was not enacted into the mechanism; if the price were allowed to plummet, obligated entities would be capable of purchasing RECs at lower prices to meet past RPOs, which would clear the market and allow the price to rise back to equilibrium levels.

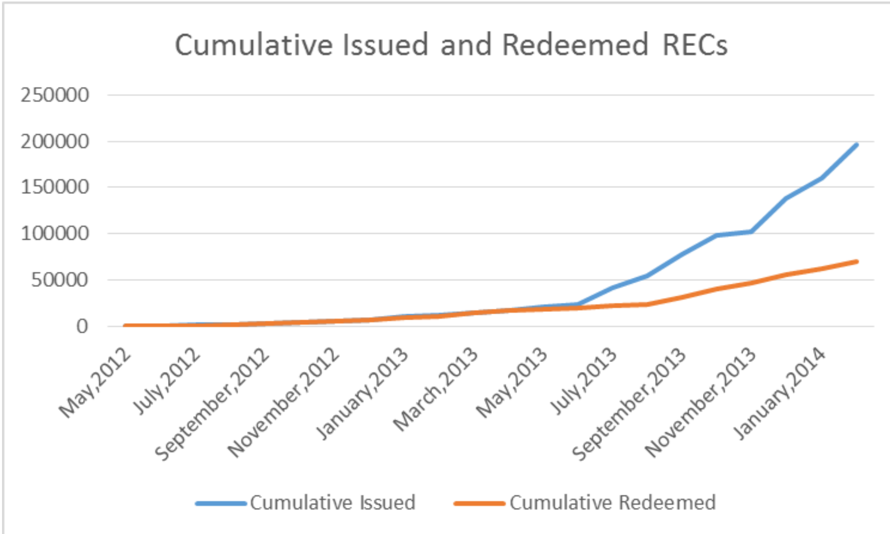

Figure 19: Cumulative issued and redeemed Indian solar RECs[46]

The lack of REC demand creates significant investment risk for projects using this mechanism. RPOs must be enforced nationwide for this mechanism to adequately support large-scale PV investment. States, such as Gujarat, that have nullified previous years' RPO noncompliance cause detrimental harm to the feasibility of the Indian REC system. Currently, the oversupply coupled with unpredictable state enforcement make projects using this mechanism largely not bankable. Financing of projects using this system will require a large 3rd party base PPA rate to reduce the exposure to REC risk.

Costs of Utility-Scale Solar Photovoltaic Development

While the costs of large-scale solar PV development remain high in comparison to conventional generation, there have been dramatic cost reductions in PV technology. The cost of PV technology is said to follow Swanson's law: each time the volume of PV cell manufacturing capacity doubles, the cost of PV cells decreases by 20%.[47] The extreme decreasing cost trends of PV cells since the late 1970s exemplifies this law, shown graphically in figure 20.

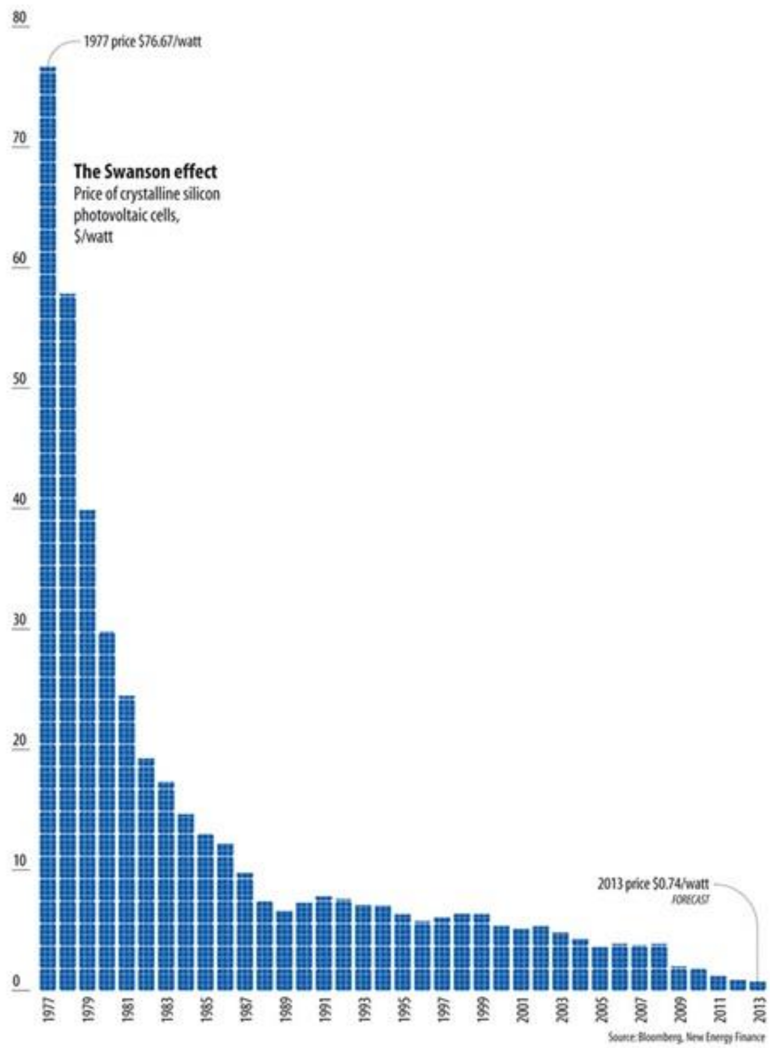

Figure 20: Swanson's law on the price of PV cells[47]

Since 1977, the price of PV has fallen dramatically from $76.67/watt (per watt of peak power) to about $0.70/watt in December, 2013.[47,48] While this price drop decreases the PV module cost component of LCOE, construction and installation of the modules add on a significant per watt cost to the final LCOE.

The LCOE of large-scale PV is most significantly made up of the large capital costs of the project. Conservatively, large-scale PV systems in India have a benchmark capital cost of about Rs. 150 million (2012).[39] This capital cost is made up of PV modules, mounting structures, inverters (i.e. power conditioning units), power evacuation to grid, preliminary operating expenses, and civil works.[39] This cost breakup of the capital cost is shown in figure 21.

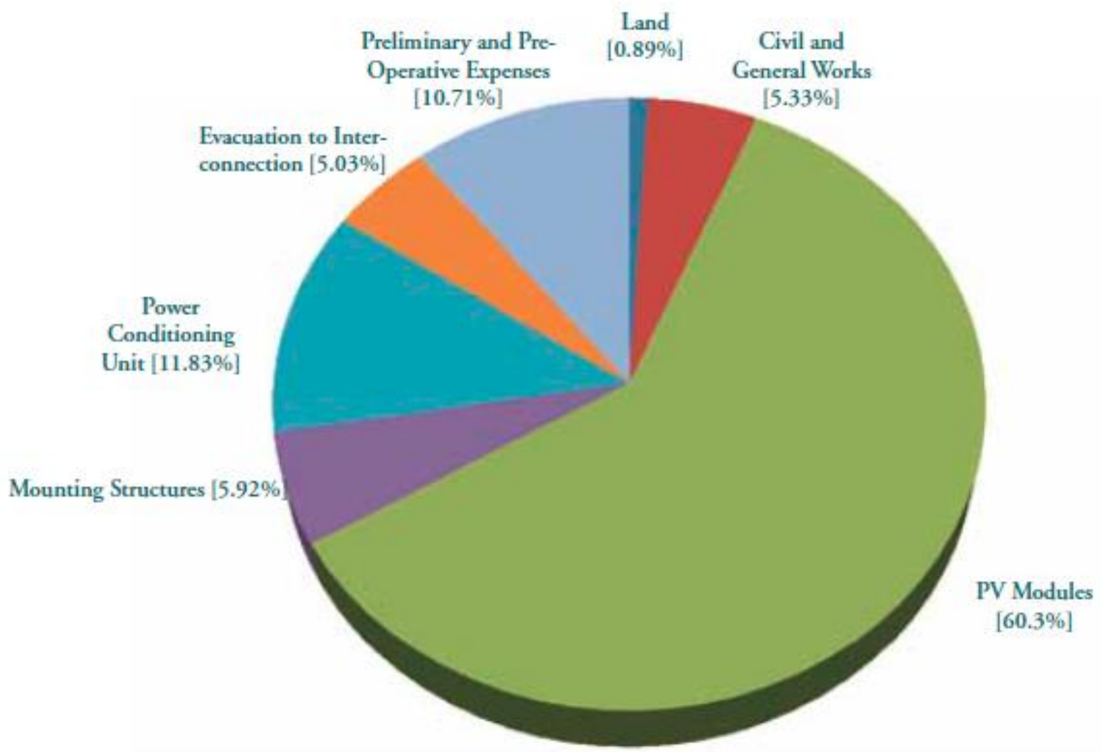

Figure 21: Large-scale PV system capital cost breakup[39]

Note that the largest component of the capital cost is the PV modules, followed by the inverters.[39] The land requirement for PV power plants is typically about 5 acres per MW of installed capacity.[39] More efficient technologies will require less land to reach the same capacity. Transmission from the PV plant to the grid includes the installation and commissioning of cables and electrical equipment to upload the electricity to the substation.[39] The preliminary operating expenses are allocated for designing of the plant, acquiring permissions, and interest payments.[39] The mounting structure of the plant will make up a larger component if a tracking structure is used rather than a fixed structure. While the capital cost of PV projects has decreased to a level closer to Rs. 10 million per MW, the cost proportions shown in figure 21 remain largely the same.

Operation and maintenance expenses will also add to the LCOE over the lifetime of a PV project. These expenses consist of warranties, repairs, and cost of certain employees.[39] An example of an operation and maintenance expense is the cleaning of panels in order to retain maximum solar exposure. Unless in the event of meteorological or other significant damage to the plant, these costs are not significant but are expected to have an inherent annual escalation of about 5.75%.[39]

The LCOE of large-scale PV must be less than the revenue stream of the project in order for the solar resource to be classified as a reserve. The current standard LCOE estimate for large-scale solar PV is about $0.34/kWh, while it is projected to be about $0.15/kWh in 2018.[49,50] The LCOE is dependent on location not only because of the fluctuations in the solar resource (chapter 4) but also because of the inherent cost differences in different regions. The LCOE is subject to the discount rate used in its calculation, which varies according to the perceived risk or volatility of the project's costs. There are several different mechanisms, discussed within this chapter, by which Indian PV investors can seek to maximize their revenue stream (LROE) over the LCOE of the project.

Chapter 6

Financial Analysis of the Indian Solar Resource and Reserve

Methods of Photovoltaic Power Plant Financial Analysis

The feasibility of solar PV investment in India is best evaluated with a financial analysis of potential projects in India. Financial analysis of the solar resource will identify the economic viability of large-scale PV projects and will define the amount of solar reserves in a given project location. Adequate financial analysis includes valuation metrics that account for asset and market factors by interpreting the risk structure of the relevant asset. Valuation of large-scale solar PV systems aims to identify the fair market value of a project assuming continued use; this means that the buyer and seller of the valued asset intend to continue utilizing the asset as it is currently operating.[51] There are several methods used to value large-scale PV assets. The most widely used methods that are taken into account in project valuation are the cost approach, the market approach, and the income approach.[52] This section provides a description for each of these valuation methods and provides further detail into completing the income approach method.

The cost approach utilizes the upfront investment of the system to determine the value of a PV system.[52] This method does not derive an accurate fair market value as cost is not equivalent to value, but it is an important metric in understanding the investment required to develop the project.[52] Cost of a power asset must also be considered after applicable rebates and government incentives taken into account.[52] PV systems require maintenance and often replacement of inverters, which must also be taken into account by the cost valuation method.[52] Valuation using cost is especially important in selling or purchasing of an existing PV system, which may have already utilized the applicable cost benefits of owning the system.[52] A solar resource may not be capable of economic conversion (i.e. reserve classification) if the cost valuation of the project is too high.

The market approach to large-scale PV asset valuation uses transactions of PV systems on the market to determine value.[52] While there are buyers and sellers of large-scale PV systems, these transactions are typically confidential, which creates a lack of market data to use for valuation. Furthermore, this valuation is only accurate if the transaction occurs for a system in the same region as the subject PV system.[52] This method is capable of accounting for "green" value of projects in a specific location where buying entities may appraise solar PV plants at a higher value due to the perceived benefit of owning renewable energy.[52] Despite "green" value accounting, this method applied to large-scale solar PV suffers largely from a lack of public and proximate market transaction data.

Valuation via the income approach is completed by calculation of the large-scale PV system's net present value (NPV) and is the most reliable method for risk-accounted financial valuation.[52] The NPV of an asset can be defined as the sum of its present and future cash flows discounted to present value.[53] Future cash flows are discounted to present value in order to calculate the asset in terms of equivalent dollar values by accounting for the time value of money. The basic equation for NPV is displayed in equation 3.[53]

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1 + r_d)^t} \tag{3}$$

In equation 3, CF_t is the cash flow (cash inflow or cash outflow) in year t, and r_d is the discount factor.[53] The discount rate is the expected return from a project that matches the risk profile of a project in which the entity would invest.[53] A positive NPV indicates that the solar resource convertible into electricity is economically viable and is therefore a reserve. An NPV of approximately 0 indicates that the solar resource is a marginal reserve. A negative NPV indicates that the solar resource is a subeconomic resource.

Cash flows in a year is calculated as the change in cash from the beginning of the year to the end of the year. In accounting terms, cash flows is calculated as:[54]

EBIT
- Corporate Tax
+ Depreciation
+ Amortization
- Change in net working capital
- Capital Expenditures
+ After-tax asset sales
= Capital Cash Flows

In large-scale PV assets, earnings before interest and taxes (EBIT) are calculated by the revenue streams (PPA and RECs) less the operating expenses. The change in net working capital accounts for the immediate liabilities tied to the asset. After-tax asset sales accounts for any gain in cash due to sale of PV materials; at the end of a PV system's PPA, an investor may choose to sell the PV materials, which would fall under this category. The interest expense and debt principal repayment is further subtracted from capital cash flows to calculate net cash flows.

Although discount rates can be calculated in different methods, the weighted average cost of capital (WACC) is most commonly used by business and takes into account the total risk structure of an asset.[53] The discount rate is a measure of a firm's cost of capital, which can also be described as a firm's opportunity cost of utilizing the capital.[55] Using capital for investment in an asset is always accompanied with the cost of foregoing the opportunity to spend the capital for use in another investment. WACC accounts for all sources of capital raised for an investment, which includes capital raised through debt (i.e. loans and/or bonds) and capital raised through equity (i.e. internally generated funds and/or ownership offerings).[55] The WACC calculation is shown in equations 4 and 5.[53,55]

$$r_{WACC} = \frac{E}{D+E}\left(r_e^L\right) + \frac{D}{D+E}\left(1-t\right)r_d \tag{4}$$

$$r_e^L = r_f + \beta(\text{Risk Premium}) \tag{5}$$

In equation 4, r_e^L is the discount rate for leveraged equity (i.e. the cost of equity: equation 5), r_d is the average interest rate on long-term debt (i.e. the cost of debt), t is the corporate tax rate, E is the targeted equity, and D is the targeted debt.[53,55] The E and D ratios in equation 4 are factored into the WACC equation to proportionately account for the costs of equity and debt. In equation 5, r_f is the risk free rate (rate of return for riskless asset, typically government bonds), Risk Premium is the expected return of a stock over the risk free rate, and β (beta) is a coefficient used to model the dependence of an asset's fluctuation in conjunction with market volatility.[55,68] A beta of 1 has perfect dependence on market fluctuations, a beta less than 1 is less volatile than the market, and a beta greater than 1 is more volatile.[53]

For privately owned large-scale PV investors, beta is inherently difficult to identify and may not capture the true value of the asset's risk. A solar investing firm must have a significant history of earnings to be capable of comparing its earnings volatility to that of the market.[55] If a firm does not have sufficient data, the firm should use an average of the betas of publicly traded firms (i.e. whose betas are published) that are similar to the investing firm.[55] The firms used to calculate the beta must be subject to the same fluctuations from economic factors as the investing firm.[53] In the case of large-scale PV investment in India, table 2 provides an average beta calculation from publicly traded firms within the Indian solar industry.

Table 2: Betas of publicly traded companies in the Indian solar industry[56,57,58]

Industry	Industry Wt	Company	Exchange	Beta	Avg Beta
India EPC	5%	Welspun Projects Ltd	BSE	2.00	2.22
		Lanco Infratech Ltd	BSE	2.43	
India IPP	5%	Tata Power Co	BSE	1.01	1.01
India Energy	10%	Videocon Industries Ltd	BSE	1.12	1.12
India Power Equip Mfr	10%	Bharat Heavy Electricals	BSE	0.98	0.98
India PV Mfr	50%	XL Energy Ltd	BSE	1.68	1.68
Global PV Mfr	20%	First Solar	NASDAQ	1.99	1.89
		SMA Solar Technology	Berlin SE	1.20	
		Motech Industries	Berlin SE	1.53	
		SolarWorld AG	Berlin SE	2.16	
		SunPower Corp	NASDAQ	2.56	

The companies included in table 2 are publicly traded on the Bombay Stock Exchange (BSE), NASDAQ, and the Berlin Stock Exchange and are subject to similar economic factors as private solar PV investors. This beta analysis of comparative companies utilizes industry weights to provide proportional beta accounting with preference for industries that are more closely affected by similar economic factors. India engineering, procurement, and construction (EPC) companies build the PV systems for PV investors. India EPC, IPP, and energy companies must be factored in to account for the broad effect of market factors on large-scale companies with stake in the Indian electricity industry. While the India EPC, IPP, and energy companies included in table 2 are the most applicable to account for the Indian electricity industry, these companies compete in many industries other than PV. These companies are therefore affected by other economic factors in addition to those affecting PV, and so only carry a collective weight of 20%. The India PV manufacturing company, XL energy, is subject to economic factors that align closest to those affecting PV IPPs. As such, XL Energy carried 50% of the weight because it is the most exemplary model of PV industry risk for Indian PV investors. Additionally, global PV manufacturers that affect the Indian solar market are included to account for global economic factors. These were also weighted with only 20% proportion as they are affected by economic factors external to the Indian market. Ideally, a private Indian PV investment (IPP) company would model their beta from a publicly owned, large India solar PV IPP company; however, there are no such Indian IPP companies that only invest in solar PV. Using the betas and weights in table 2, the average beta for a privately owned solar PV IPP investment company is about 1.59.

Betas calculated by using comparative company betas can undervalue the inherent investment risk for privately owned companies.[55] This issue arises because publicly traded company betas are calculated assuming that the company is capable of diversifying away market risk by investing in many different assets.[55] For privately owned companies, this is not always possible in cases where owners have their entire wealth in the company's assets and have thus not diversified away inherent market risk.[55] To account for this risk, it is often prudent and conservative to allow the WACC to be a measure of the base cost of capital and to add an additional risk value to the discount factor at the discretion of the private owner.[55]

Another method used to evaluate an investment is the internal rate of return (IRR), which can also be used as a measure of opportunity cost. The IRR is equal to the discount factor that must be used on a set of cash flows to create an NPV of 0.[59] IRR is the rate of return that a company achieves by investing in its internal operations.[59] In corporate finance, this metric is often used to evaluate a potential project investment with respect to another investment, such as market securities; a higher IRR indicates a more lucrative return on equity.[59] The IRR of a company is also used to discount cash flows from other investments. The IRR is used as the discount factor because it is a measure of the rate of return that the company already receives (i.e. expects to receive) from existing operations, or the rate of return that could otherwise be attained from investing elsewhere.[59] If a company values an investment opportunity using the IRR opportunity cost as the discount factor, the opportunity must have a higher IRR than the company's existing IRR in order for the investment to have a positive NPV.

Resource-Reserve Classification of Halo Energie's 5MW Komreddypalle Photovoltaic Investment Opportunity

To complete a financial analysis of the solar PV resource in India, this report utilizes a financial analysis for a real world investment opportunity. The data used within this section is for an Indian IPP, Halo Energie Pvt Ltd, that has received permission from the state of Andhra Pradesh to develop a 5 MW solar PV plant in the town of Komreddypalle.[60] The Engineering Procurement and Construction (EPC) company selected by the investor (Halo Energie Pvt Ltd) is Microsol International.[60] The total capacity of the designed plant is about 5.249 MW.

The power plant site is 31.5 acres and is located approximately 2 km from the closest 33 kV substation.[60] The project location is 16.5616°N and 77.9548°E.[60] Figure 22 shows this proposed location for the solar PV plant in Andhra Pradesh within the Mahbubnagar district.[60] The Mahbubnagar district has a strong solar irradiance, given its southern Indian location south of the tropic of cancer and north of the equator. This district's southern location limits the low solar altitude during winter months and the high solar altitude during summer months, which minimizes the amount of air mass the solar energy must travel through.

Figure 22: District of Komreddypalle PV plant[60]

The site is subject to an excellent solar resource, having a mean irradiation that varies from about 4.7 to 5.6 kWh/m^2/day.[60] In addition, this region of India typically experiences about 300 sunny days per year.[60] The monthly GHI of the site location is included in figure 23.

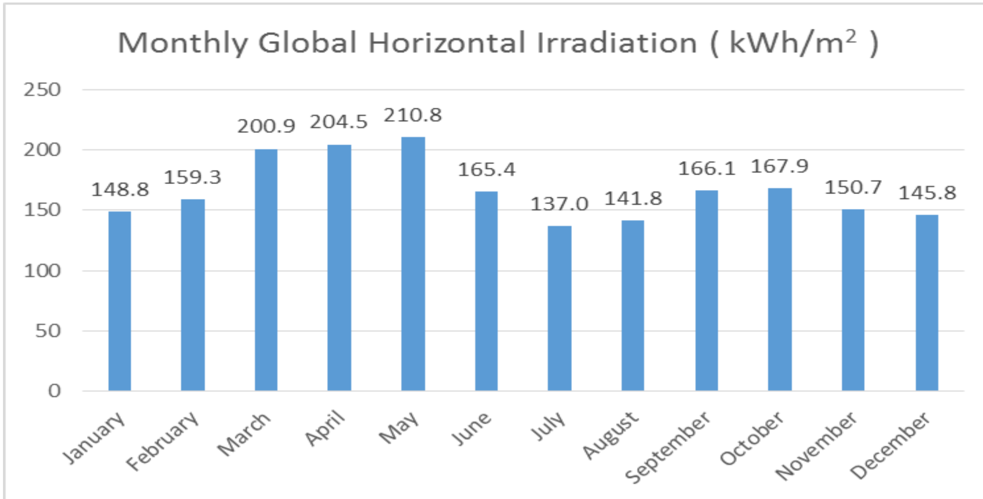

Figure 23: Monthly Global Horizontal Irradiation at Komreddypalle site[60]

The GHI shown in figure 23 is derived using satellite mapping, and so is an indicated solar resource. The uncertainty of this data is limited by comparing the satellite solar resource data to nearby ground measurements of the solar resource. The location receives the most irradiation of about 200-210 kWh/m^2 during the months of March, April, and May. These months experience the most solar irradiation as the solar declination reaches 0° in late March and continues increasing through June; during these months, the solar altitude will be the greatest. July and August have the least irradiation largely due to the increased humidity and overcast conditions that occur during the monsoon season in Andhra Pradesh. This monthly irradiation yields a total annual irradiation of just under 2,000 kWh/m^2. The annual DNI of this location is about 1,775 kWh/m^2.[61]

Solar Resource Quantification

Using the irradiation measurements at the project's location, the indicated solar resource at the project's location can be identified. The 5 MW site requires a land area of 31.5 acres to place the solar collectors on. This area of land is where the relevant solar PV resource exists. The calculation of the annual global horizontal solar resource is included in equation 6.

$$31.5\, acres \times \frac{4046.86\ m^2}{1\, acre} \times \frac{2000\ kWh}{1\ m^2} \approx 2.55 \times 10^8\ kWh \qquad (6)$$

Therefore, the applicable indicated solar resource at the project's proposed site is about 255 million kWh per year. Using a similar calculation, the DNI component of the indicated solar resource is about 226 million kWh per year. As presented in chapter 4, the DNI value is less than the GHI value as GHI is inclusive of all DNI, DHI, and ground reflectance light components.

From the indicated solar resource, the amount of the resource capable of solar reserve classification can be identified. In order for the solar resource to be classified as a solar reserve, the project must be capable of economically converting the solar resource into electricity. A large portion of the 31.5 acres will not be covered with panels to eliminate inter row shading of the modules. The solar resource that is theoretically convertible is the amount of solar irradiation that is incident on the total surface area of the solar modules.

To further identify the amount of the solar resource that is expected to be converted, the expected energy yield (i.e. electricity generation) of the project must be derived using the technical factors of the PV plant. The technical details of the proposed power plant are included in table 3.

Table 3: Technical details of the Komreddypalle PV plant[60]

Parameter	Details
Photovoltaic Technology	Mono-crystalline Silicon
Module	Solon Black XT 290W
Module Efficiency	15.88%
Number of Modules	18,100
Modules in Series	20 per string
Modules in Parallel	905 strings
Total Module Surface Area	33,319 m^2
Inverter	AEG Protect PV 500
Number of Inverters	10
Nominal Power	5.249 MW

The total of 18,100 modules for this project accumulates to a total surface area of 33,319 m^2; this surface area is the solar resource collecting area in comparison to the 127,480 m^2 (31.5 acres) of total land surface. The surface area covered by modules with respect to the surface of the land can be seen in figure 24, which is the project layout of the module tracking systems. The solar resource that the remaining 94,161 m^2 receives is a subeconomic resource as it cannot be feasibly converted due to spacing, shading limitations, inverter space, and unused sunk cost land. Additionally, the modules are to be installed on a Solon Tauri single-axis tracker.[60] This tracking system allows the panels to track the sun from east to west throughout the day, effectively minimizing the angle of incidence of the solar irradiance. By installing a tracker, the amount of global irradiation incident on the modules' plane of array increases to about 2,432 kWh/m^2 per year.[60] This increase of about 21.6% from the GHI value of 2,000 kWh/m^2 per year is a result of the tracking modules, which receive greater DNI as well as albedo from ground reflectance; the irradiance incident on the panels would be 2,000 kWh/m^2 per year if the modules were installed horizontally without tracking capability. Using the tracking irradiation incident on the panels with the total module surface area (table 3), the solar resource that the collectors receive (but do not 100% convert) is about 81 million kWh per year.

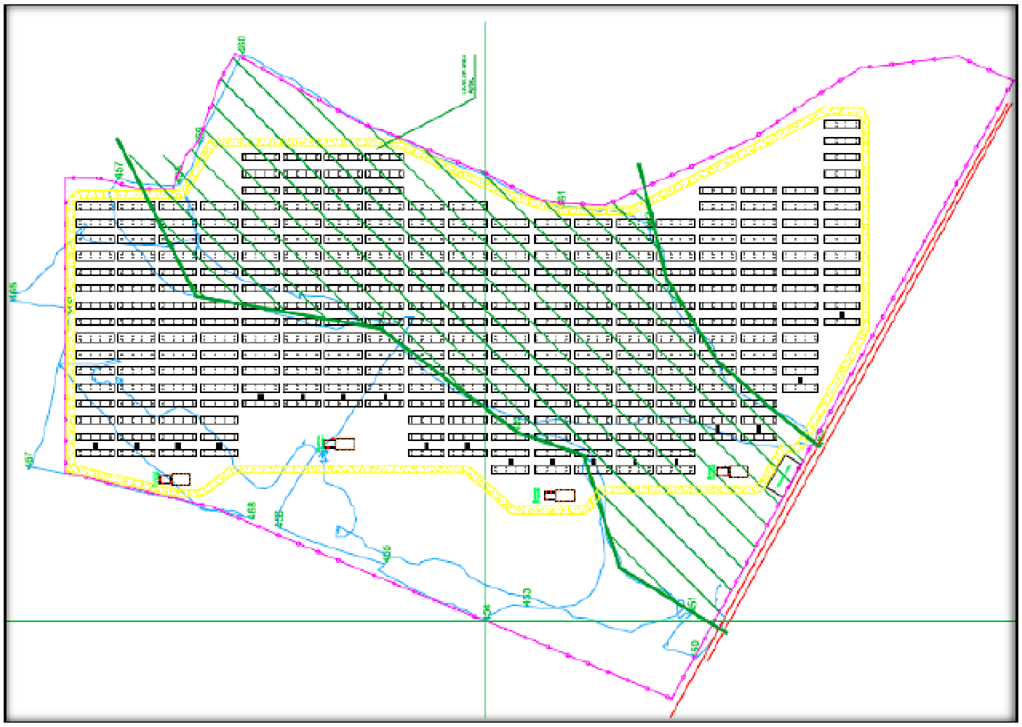

Figure 24: Layout of 5MW Komreddypalle PV plant[60]

Using the solar resource incident on the plane of the module array, the PV electricity generation can be determined. EPC companies use sophisticated software to calculate the generation of the modules based on the hourly or sub-hourly meteorological data (similar to System Advisor Model).[62] The generation is determined by combining the operation voltage of the module arrays given the temperature and irradiance conditions at the specified time intervals.[62] Losses from various factors are assumed based on PV system specifications and industry averages. Figure 25 provides an energy flow diagram of the solar resource energy conversion for an entire year.[60] Note that, in figure 25, the initial solar irradiation accounted for is 1,999 kWh/m^2, which is then increased by 21.6% to account for the tracking modules that decrease the angle of incidence throughout the day. The solar resource is then reduced by 2.4% to account for losses associated with the incidence angle. Because the panels only track on a single axis, the incidence angle in the north-south plane experiences reflective losses as the incidence

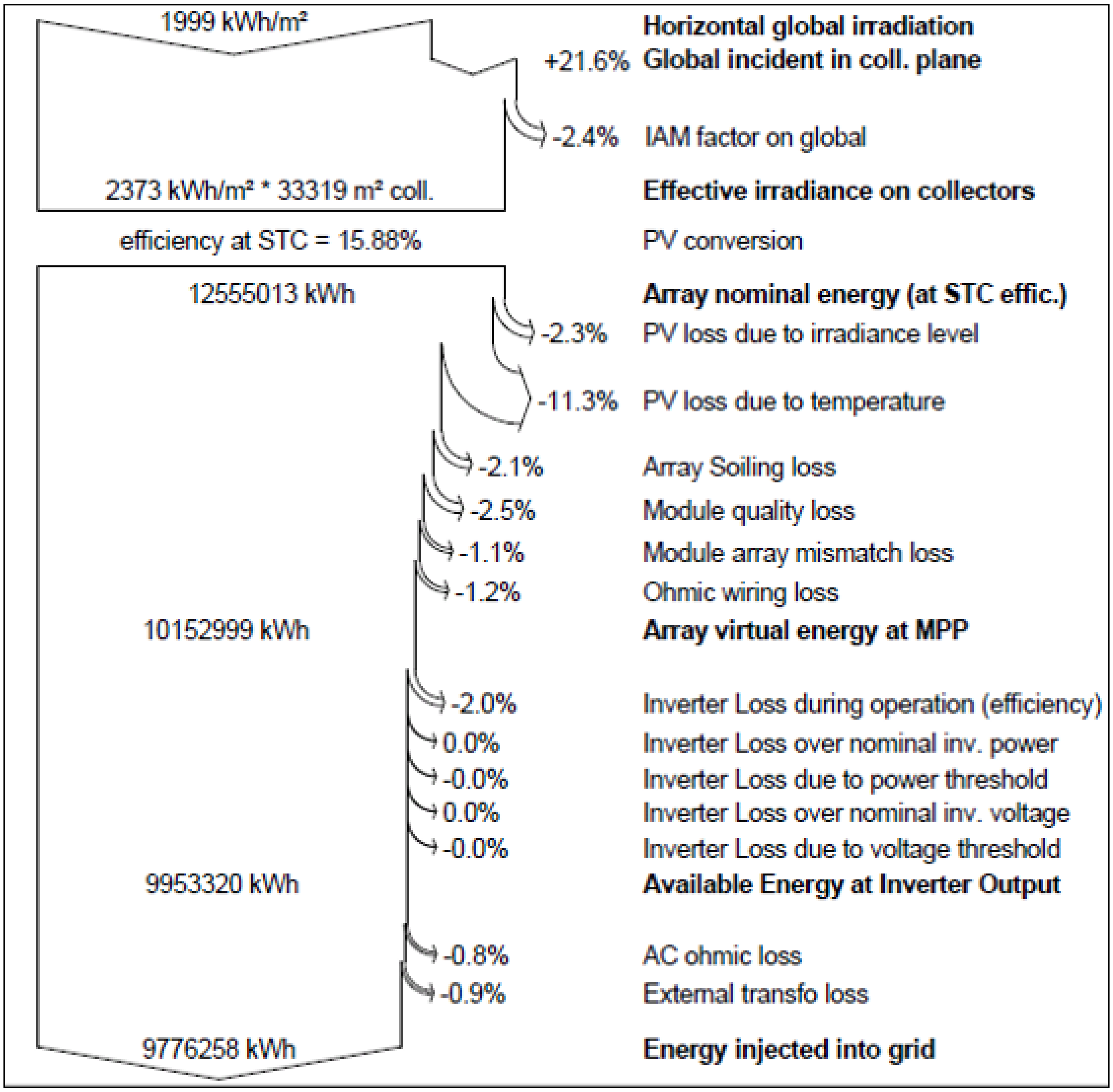

Figure 25: Energy flow diagram for 5MW Komreddypalle PV plant[60]

angle differs from normal to the plane of the module (note that IAM refers to Incidence Angle Modifier).[63] After accounting for the IAM, the effective annual solar irradiation incident on the modules is 2,373 kWh/m^2, multiplied by the module surface area (33,319 m^2) and efficiency (15.88%) to derive a total PV conversion solar resource of 12,555,013 kWh per year. Notable energy losses include PV loss due to temperature, which is a result of solar cells performing below standard conditions at the high temperatures experienced in Komreddypalle, India. Soiling due to dust accumulation on modules also creates a notable loss. Module array mismatch energy loss is a result of slight differences in manufactured module voltages, which create losses across system arrays. The 5 MW system has high efficiency inverters, which generate losses of less than 0.1%. The total convertible solar resource that is injected into the grid is about 9,776,258 kWh per year.

Using the expected energy conversion, the solar resource can be split into subeconomic resources and the solar resource component that is capable of meeting reserve classification. After tracking is accounted for, the total solar resource incident on the module surface area is about 81 million kWh per year. The roughly 71.3 million kWh of unconverted solar resource cannot be economically converted due to reflective losses from the angle of incidence, efficiency constraints, and expected electrical losses. Therefore, this 71.3 million kWh of unconverted solar resource are classified as a subeconomic resource, while the 9,776,258 kWh of convertible solar resource is the portion capable of being classified as a solar reserve or marginal reserve.

Financial Analysis of the Converted Solar Resource

A financial analysis of the proposed project must be completed to determine if converting the 9,776,258 kWh annual solar resource is economically viable, and therefore, is classified as a reserve. A financial analysis of the project determines economic viability by defining the selling price of PV generated-electricity and government incentives/policies with respect to the LCOE of the PV plant (covered in chapter 3). The initial cash outlay of the company is equal to the initial investment to install and commission the PV project; this is the most important factor in determining LCOE. The upfront costs of this project are included in table 4. The module costs of the project make up the largest single upfront cost at $3.3 million.[60] The steel cost component includes the cost of raw steel and fabrication completed to properly mount the modules.[60] Civil works include access road building, drainage system development, module mounting, and cable laying.[60] Note that due to cheap labor costs, the cost of civil works is significantly cheaper than

Table 4: Costs of 5 MW Komreddypalle project[60]

Project Costs	
Modules	$ 3,306,870
Inverters	$ 918,000
Foundation and Steel	$ 917,689
Electrical Cables & Equip.	$ 853,206
Misc. Equip.	$ 101,529
Civil Works	$ 165,289
Add'l EPC Services	$ 580,264
Total EPC	$ 6,842,847
Land and Land Prep.	$ 545,455
Contingency	$ 171,071
Total Cost	**$ 7,559,373**

PV installation civil works in the US. Design, project management, testing, and commissioning are costs incurrent in the additional EPC services cost component. The total EPC cost of the Komreddypalle power plant is about $6.84 million, which gives a total installed project cost of about $7.56 million after land and contingency costs.[60] These costs are used later in this section to compute the LCOE of the project.

Halo Energie's Komreddypalle project has won its permissions to sell its PV-generated electricity via 3rd party PPA and sale of RECs. Halo Energie has identified a pharmaceutical company plant near the Komreddypalle project site, which draws its electricity from a 33 kV substation.[43] As discussed in chapter 5, it is important that the plant draws from a 33 kV substation to avoid grid faults that 11 kV substations are prone to. The pharmaceutical plant consumes more electricity each day than the 5 MW power plant is capable of producing; therefore, the 3rd party can offtake 100% of the PV generation.[43] This is beneficial for the investor as it will not need to negotiate multiple PPAs. In PPAs between the PV investor and the 3rd party end-user, the investor must negotiate an electricity price against the competing Indian electricity market rate. The annual average cost of electricity of the pharmaceutical company is approximately Rs. 6.8/kWh, which is higher than the typical Rs. 6/kWh non-domestic rate.[43] Given this high market electricity rate, the investor negotiated a PPA of Rs. 7/kWh.[43] This 3rd party electricity rate is equivalent to about $0.116/kWh. This PPA is negotiated for 5 years, after which a new PPA must be negotiated with the same company or a new company.[43] Under this mechanism, the investor also receives RECs for every MWh of electricity injected into the grid.

The PV system operating expenses are the other components that make up the LCOE. These expenses are incurred throughout the lifetime of the project. Operating expenses typically include operation and maintenance (O&M), general and administrative, insurance premium, and salaries and wages. O&M includes cleaning modules, servicing inverters, tracker servicing, performance monitoring, and unscheduled maintenance.[64] This expense is typically charged on a per MW basis, which varies with the contract. O&M contracts are often signed with the EPC that installed the plant as an added benefit for the EPC company. The benchmark cost of O&M is Rs. 1.1 million per MW, or about $18,300/MW.[65] This O&M cost escalates at 5.72% per year to account for inflation of costs.[65] The insurance premium is often set within the O&M contract to cover unexpected costs; this premium is typically taken as 0.15% of the total installed cost.[60,65] General and administrative expenses are set internally by the investor as well as salary and wage expenses.

While this financial analysis is able to quantify many parameters with minimal uncertainty, there are still several assumptions that must be made in order to successfully complete a financial analysis of the solar reserve. The assumptions made for Halo Energie's 5 MW Komreddypalle plant are shown in table 5. One of the most important assumptions associated with the financial analysis is the PPA contracts negotiated for the final 20 years of the project's life (assuming 25 year plant lifetime). In this model, it is assumed that the second 5 year PPA will begin at a PPA price of RS. 7.5/kWh ($0.125/kWh) with a 2.5% annual escalation factor to reflect the increase in market electricity prices. For the final 15 years, it is assumed the PPA price begins escalating at 5% per year; this escalation reflects the expected exponential

Table 5: Komreddypalle 5 MW Financial Analysis Assumptions

Parameter	Assumption
Years 6-10 PPA	RS. 7.5/kWh with 2.5% annual escalator
Years 11-25 PPA	5% annual escalator
General & Administrative Expense	1% Total electricity sales
Salary and Wages	$16,670/year
Debt @ 70%	$5,291,561
Equity @ 30%	$2,267,812
Debt interest rate	12.50%
REC Clearance	20%
REC decrease after March 2017	50% per 5 years
Commissioning Date	March, 2014

increase in electricity demand as well as the expected 5% annual increase in the APPC.[60] It is typical for a private IPP to finance power projects with 70% debt. To finance a PV project with debt, the investor may issue corporate bonds or acquire a loan from a financial institution. While banks may also provide loans for PV development, this model assumes financing via the Indian Renewable Energy Development Agency (IREDA). IREDA has assisted Indian renewable energy growth by financing projects; its current interest on solar PV loans is approximately 12.50%.[66] The remaining $2.27 million is equity capital. For private PV investors, this equity amount typically consists of internally raised funds from either the owners' investments or sourced investments from others in exchange for private stock in the company or plant. Given the volatility and uncertainty in the Indian REC market, it is often conservative to include an REC clearance percentage. For the purpose of the Komreddypalle PV project, an REC clearance of 20% is assumed to account for the oversupply and lack of demand in the REC market detailed in chapter 5. This 20% is a conservative estimate of PV REC clearance that the Indian PV industry commonly assumes.[43] Additionally, the current REC floor and forbearance prices are set until March, 2017, after which the new deducted prices have not been determined.[40] This analysis conservatively assumes that the REC prices will drop 50% after March, 2017 and will drop at this rate after each set of 5 years. As well, the cleared REC price is assumed to be at the floor price (e.g. Rs. 9,300 for first 3 years) every year. The commissioning date is assumed to be March, 2014 to allow for round accounting in project years to follow the REC deductions.

The discount factors for the financial analysis are determined using the known variables for equations 4 and 5. The risk free rate of return, r_f, is determined using the 10-year Indian government bond yield. Using recent yield data, this rate is about 8.779%.[67] The investor's beta is calculated to be about 1.59 (previous section). Note that in order for this beta to be used, it assumes that the comparable companies used have similar corporate structure in terms of equity/debt and that they are subject to similar market volatility to each other. The risk premium is assumed to be about 4.50% as an acceptable return premium for the purpose of the Komreddypalle PV analysis. Using equation 5, the levered cost of equity, r_e^L, is calculated to be about 15.93%. Note that additional risk could be added onto this discount factor to account for the inherent risk of the REC mechanism and lack of REC clearance; however, utilizing an REC clearance factor accounts for this risk within the financial model itself. The levered return on equity is used as the discount factor for the levered (i.e. including debt obligations) cash flows as the equity holders have full access to the net cash flows after interest and principal payments.[54] The weighted average cost of capital is determined using equation 6, where equity is 30%, debt is 70%, the tax rate is 20.01% (i.e. the Minimum Alternate Tax), and the cost of debt, r_d, is 12.50% (i.e. the debt interest rate). The tax rate is taken as the Minimum Alternate Tax (MAT) instead of the higher corporate tax because the PV plant is able to claim accelerated depreciation, allowing the investor to only be responsible for paying the MAT.[60] Using these parameters and equation 4, the WACC is calculated to be about 11.78%. The WACC is used as the discount rate for the unlevered (i.e. without debt financing) cash flows as both the debt lender and equity holders have access to the cash flows before interest and principal payments.

Year		0	1	2	3	4	5	6	7	8	9	10
Gross Electricity Production	**(kWh)**	0	9,776,258	9,727,377	9,678,740	9,630,346	9,582,194	9,534,283	9,486,612	9,439,179	9,391,983	9,345,023
Aux Consumption	0.50%	0	48,881	48,637	48,394	48,152	47,911	47,671	47,433	47,196	46,960	46,725
Transmission Loss	0.50%	0	48,881	48,637	48,394	48,152	47,911	47,671	47,433	47,196	46,960	46,725
Net Production		0	9678495	9630103	9581952	9534043	9486372	9438941	9391746	9344787	9298063	9251573
PPA Price/kWh		$ -	$ 0.116	$ 0.116	$ 0.116	$ 0.116	$ 0.116	$ 0.1250	$ 0.1281	$ 0.1313	$ 0.1346	$ 0.1380
Total PPA Sale		$ -	$ 1,122,705.47	$ 1,117,091.94	$ 1,111,506.48	$ 1,105,948.95	$ 1,100,419.20	$ 1,179,867.57	$ 1,203,317.44	$ 1,227,233.38	$ 1,251,624.64	$ 1,276,500.68
REC Price/MWh		$ -	$ 155.00	$ 155.00	$ 155.00	$ 77.50	$ 77.50	$ 77.50	$ 77.50	$ 77.50	$ 38.75	$ 38.75
RECs Cleared			20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Total REC Sale		$ -	$ 299,925.00	$ 298,530.00	$ 296,980.00	$ 147,715.00	$ 147,017.50	$ 146,242.50	$ 145,545.00	$ 144,770.00	$ 72,036.25	$ 71,687.50
Total Electricity Sales		$ -	$ 1,422,630.47	$ 1,415,621.94	$ 1,408,486.48	$ 1,253,663.95	$ 1,247,436.70	$ 1,326,110.07	$ 1,348,862.44	$ 1,372,003.38	$ 1,323,660.89	$ 1,348,188.18
O & M		$ -	$ 91,500.00	$ 96,733.80	$ 102,266.97	$ 108,116.64	$ 114,300.92	$ 120,838.93	$ 127,750.92	$ 135,058.27	$ 142,783.60	$ 150,950.82
General & Administrative Expenses		$ -	$ 14,226.30	$ 14,156.22	$ 14,084.86	$ 12,536.64	$ 12,474.37	$ 13,261.10	$ 13,488.62	$ 13,720.03	$ 13,236.61	$ 13,481.88
Insurance premium		$ -	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06
Salary & Wages		$ -	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00
Operating Income		$ -	$ 1,288,895.10	$ 1,276,722.86	$ 1,264,125.58	$ 1,105,001.60	$ 1,092,652.36	$ 1,164,000.98	$ 1,179,613.84	$ 1,195,216.01	$ 1,139,631.62	$ 1,155,746.41
Book Depreciation		$ -	$ 1,075,233.94	$ 910,400.57	$ 770,836.17	$ 652,666.98	$ 552,613.13	$ 467,897.54	$ 396,168.85	$ 335,436.16	$ 284,013.80	$ 240,474.48
Loan Interest		$ -	$ 636,641.11	$ 570,496.58	$ 504,352.05	$ 438,207.52	$ 372,062.99	$ 305,918.46	$ 239,773.93	$ 173,629.39	$ 107,484.86	$ 41,340.33
Profit Before Tax		$ -	$ (422,979.95)	$ (204,174.30)	$ (11,062.64)	$ 14,127.10	$ 167,976.24	$ 390,184.98	$ 543,671.07	$ 686,150.45	$ 748,132.95	$ 873,931.60
Income Tax	20.01%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,788.58	$ 137,298.71	$ 149,701.40	$ 174,873.71
Profit After Tax		$ -	$ (422,979.95)	$ (204,174.30)	$ (11,062.64)	$ 14,127.10	$ 167,976.24	$ 390,184.98	$ 434,882.49	$ 548,851.75	$ 598,431.55	$ 699,057.88
Add Back Depreciation		$ -	$ 1,075,233.94	$ 910,400.57	$ 770,836.17	$ 652,666.98	$ 552,613.13	$ 467,897.54	$ 396,168.85	$ 335,436.16	$ 284,013.80	$ 240,474.48
After Tax Operating Income		$ -	$ 652,253.99	$ 706,226.28	$ 759,773.53	$ 666,794.08	$ 720,589.37	$ 858,082.52	$ 831,051.33	$ 884,287.91	$ 882,445.35	$ 939,532.37
Increase in Term Loan		$ 5,291,562.50										
CapEx and Land		$ 7,559,375.00										
Loan Principal Payment		$ -	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25	$ 529,156.25
Net Cash Flow		$ (2,267,812.50)	$ 123,097.74	$ 177,070.03	$ 230,617.28	$ 137,637.83	$ 191,433.12	$ 328,926.27	$ 301,895.08	$ 355,131.66	$ 353,289.10	$ 410,376.12
Discounted Cash Flow		$ (2,267,812.50)	$ 106,182.82	$ 131,750.84	$ 148,014.53	$ 76,199.91	$ 91,419.30	$ 135,495.09	$ 107,271.71	$ 108,848.56	$ 93,404.48	$ 93,588.77
NPV	$ 315,475.79											
IRR	17.28%											

Figure 26: Komreddypalle 5 MW Financial Model, Years 0-10. Refer to Appendix C for years 11-25 and a description of tax calculations.

With all of the financial variables established, the model of cash flows for the Komreddypalle 5 MW PV plant is included in figure 26. This figure includes the first 10 years of the project's operation; for the lifetime cash flows and the tax calculation description, refer to Appendix C. This model includes 70% debt financing with a loan repayment period of 10 years. The principal repayments are a flat $529k while the interest payments decrease as the principal is repaid. A graph of the net cash flows depicts the increasing return in figure 27.

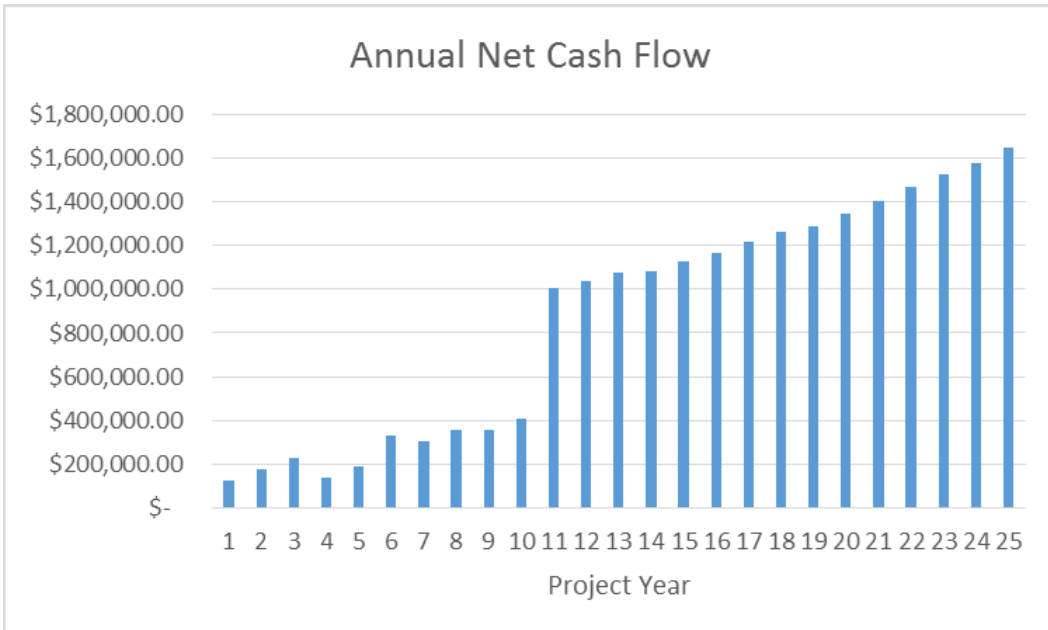

Figure 27: Annual net cash flow of Komreddypalle 5 MW PV plant

As figure 27 shows, net cash flows from the project vary from $123k to $230k in the first 5 years. These escalate to $410k in year 10 as the PPA increases and interest payments decrease. After the tenth year, debt repayments end and the cash flows increase to about $1 million. The net cash flows continue to increase with the escalating PPA through to the final year with a cash flow of about $1.65 million. Note that the financial analysis conservatively assumes a terminal value of $0. Given that debt obligations are factored into the analysis, the net cash flows belong entirely to equity holders; therefore, the discount factor is equal to the levered cost of equity, 15.93%.

Utilizing equation 3, this provides a positive NPV of about $315,476, which the investor can use to compare with other potential investment opportunities.

The total actual cash flows (i.e. non-discounted) from the project are about $19.6 million. In addition, the investment reaches the non-discounted break-even point after 10 years, which is depicted in figure 28.

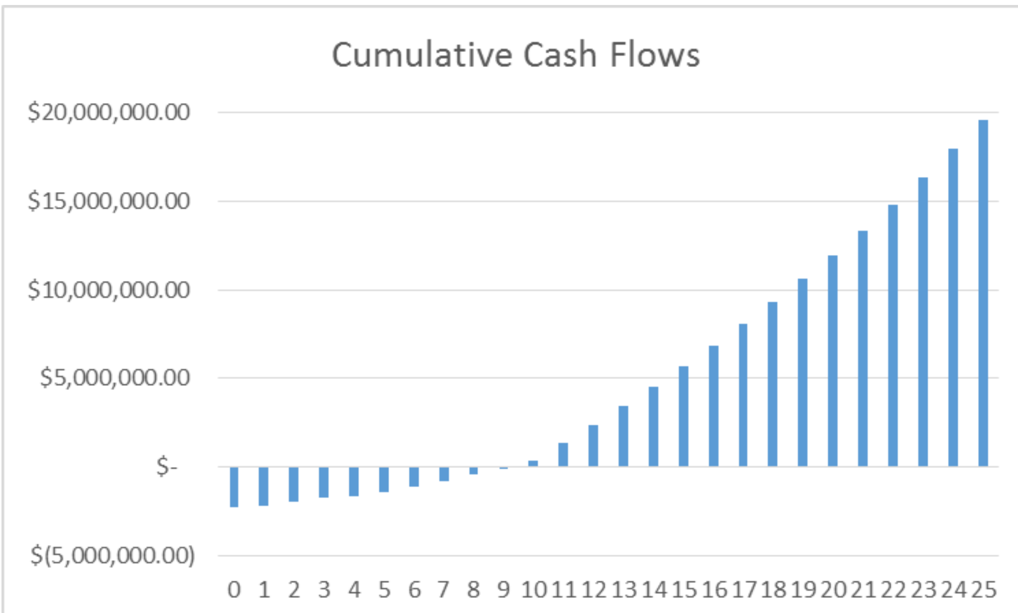

Figure 28: Cumulative cash flows of Komreddypalle 5 MW PV plant

The cumulative cash flows remain negative for the first 9 years of the project's life as the positive net cash flows begin recouping initial investment cash outlay. In the tenth year, the project reaches the breakeven as the cumulative cash flows turn positive. Additionally, the plant offers an expected internal rate of return on equity of about 17.28%. From the NPV, IRR, and breakeven metrics, the financial analysis proves the Komreddypalle power plant to be a lucrative investment opportunity.

The LCOE and LROE were calculated to provide a comparable electricity based metric using cash outflow parameters from the financial analysis. Equation 2 was used to calculate the LCOE of the power plant using the levered cost of equity as the discount factor. The cost of equity discount factor was used in order to create a cost comparable to the LROE, which uses the same discount rate. Cash outflows in the levered LCOE calculation were taken as the equity cash outflows including debt obligations. These outflows, illustrated in figure 29, included the 30% equity portion of total installed cost, all operating expenses, loan interest expense, income tax, and loan principal repayment.

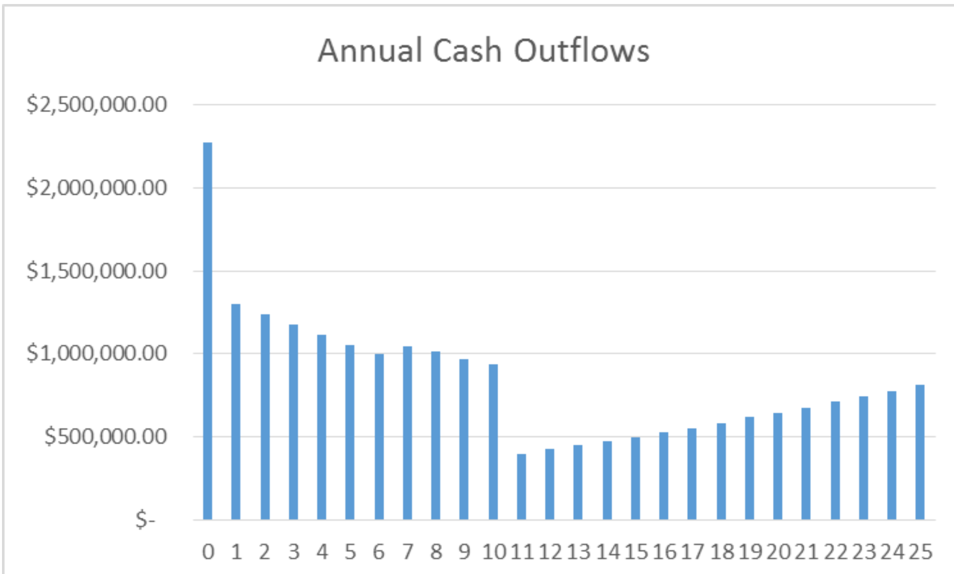

Figure 29: Annual cash outflows of the Komreddypalle 5 MW PV plant

The cash outflows decrease through year 10 as interest expense continuously decreases. After year 10, cash outflows drop due to the end of debt obligations; increases in cash outflows for years 11-25 are due to escalation of O&M costs. Depreciation was not factored into the calculation as it is a noncash item. These parameters yielded a levered LCOE of about $0.14608 per kWh. Similarly, the LROE was calculated by leveling the total discounted electricity sales with respect to electricity generation. This yielded an LROE of about $0.15156 per kWh. When applied over the entire lifetime electricity generation of the project, this represents significant profit. The levered LCOE can be utilized to compare the Komreddypalle investment against LCOEs of other opportunities specific to Halo Energie. In order to compare the power plant against other power projects irrespective of the investor, the LCOE must be calculated using unlevered cash flows to remove the effects of capital structure (i.e. equity and debt financing decisions based on the investor). The unlevered LCOE assumes 100% equity financing cash flows to calculate the core costs associated with the project. Equation 4 was used with the WACC discount factor of 11.78%. This calculation yielded an unlevered LCOE of $0.13794 per kWh. Note that the unlevered LCOE is less largely due to lack of interest payments and lower discount factor. The unlevered LROE was calculated as $0.15614 per kWh also using the WACC as discount factor.

Final Solar Resource-Reserve Classifications and Quantifications

Using the LCOE and LROE metrics, conclusions on the economic viability of solar resource conversion can be determined and the solar reserve classification quantified. With the levered LCOE of $0.14608 per kWh and levered LROE of $0.15156 per kWh, the contribution margin of electricity sales from the Komreddypalle plant is about $0.00548 per kWh. Using the unlevered financial analysis, the contribution margin of electricity sales is about $0.01820 per kWh. These contribution margins applied over the entire electricity generation over the plant's lifetime creates significant cash flows. Given these positive contribution margins, conversion of the solar resource with the Komreddypalle 5 MW PV plant is entirely economically viable. Therefore, the entire 9,776,258 kWh of the convertible solar resource is classified as a solar reserve (year 1 quantification). Across the plant's entire lifetime, the total solar reserve is equivalent to the total electricity generation of the plant, which is 230,289,058 kWh. The summary of the solar resource-reserve classification, analysis of the relevant classification, and quantification for the Komreddypalle 5 MW PV plant is shown in table 6.

Table 6: Solar resource-reserve classifications, analysis, and quantification

Classification	Analysis	Quantification
Indicated Solar Resource	Annual GHI incident on total land surface area	255 million kWh
Subeconomic Solar Resource	Spacing, shading constraints, inverter space, and unused sunk cost land	188.3 million kWh
Indicated Solar Resource	Annual GHI in plane of tracking module surface area	81.0 million kWh
Subeconomic Solar Resource	Angle of incidence, efficiency of conversion, and expected electrical losses	71.3 million kWh
Solar Reserve	Total solar resource for economically viable PV conversion	9,776,258 kWh
Total Solar Reserve	For the entire solar resource conversion (i.e. electricity generation) during the plant's lifetime	**230,289,058 kWh**

Sensitivity Analysis of the Solar Resource-Reserve

Within financial modeling of power projects, sensitivity analysis provides insight into how the outputs of the model change when the input variables are changed. In classifying and quantifying the solar resource, it is important to note how changes to input variables affect LCOE, LROE, NPV, and IRR outcomes of the model. Additionally, the analysis measures how sensitive an output variable is given an input variable change. This analysis often reveals that small changes in assumptions can lead to dramatic changes in model outputs. This sensitivity analysis quantifies the relative sensitivities of the model outputs for assumption changes in total installed costs, capital structure, and model discount factors.

Total Installed Costs Sensitivity Analysis

The total installed costs for the model were a reasonable $7.559 million including a contingency factor, but it is possible that the total cost of the PV plant could require a larger cash outlay or a smaller cash outlay given the EPC contract. Total installed costs of the plant assumed about $1.512 million/MW, which is the USD conversion for about Rs. 91 million/MW. A much more conservative total installed cost of about $7.91 million (Rs. 95 million/MW) would drive the financial model to an NPV of 0. Likewise, the total cost could also be as low as $7,083,333 (Rs. 85 million/MW) depending on the EPC contract, which would increase the project NPV. The inherent sensitivities of relevant output parameters to total cost are shown in table 7.

Table 7: Total cost sensitivities of Komreddypalle 5 MW PV plant

	Base Case	Increased Cost Case		Decreased Cost Case	
		New Value	% Δ from Base	New Value	% Δ from Base
Total Cost	$7,559,375	$7,911,605	4.66%	$7,083,333	-6.30%
NPV	$315,476	$0	-100%	$705,417	123.60%
IRR	17.28%	15.93%	-7.83%	19.25%	11.37%
LCOE	$0.14608	$0.15156	3.75%	$0.13931	-4.63%

In the increased cost scenario, a total cost increase of 4.66% creates a $0 NPV, which represents an NPV sensitivity of -100%, or about a 21.5% decrease for every percentage of total cost increase. Additionally, this cost reduces the IRR to the discount rate of levered cost of equity. Note the increase in LCOE is a result of the higher upfront cash outlay, which is commensurate with the 0^{th} year higher valued cash. As NPV is $0, the LCOE is equivalent to the LROE of $0.15156. Therefore, if the total cost of the project reached this level, the 230,289,058 kWh of total converted solar resource would be classified as a marginal solar reserve. In the decreased cost scenario (table 7) of $7,083,333 total cost, the project NPV has a positive sensitivity of 123.60% as it increases to $705,417. This trend represents about a 19.6% increase for every percentage of total cost decrease. The IRR also increases by 11.37% to 19.25%, accompanied with a decreased LCOE of $0.13931. Table 7 proves that the project NPV is highly sensitive to changes in total cost, while IRR is moderately sensitive to changes in total cost. It is important to note that while it appears that the LCOE is only slightly sensitive to total cost changes, this parameter is applied to the total generation over the plant's lifetime, so small changes in its number represent very large cost aggregates over 25 years. Thus, table 7 also proves LCOE to be highly sensitive to total cost fluctuations.

Capital Structure Sensitivity Analysis

The capital structure of the investment into a PV project can also have important effects on NPV and IRR. As shown in table 8, when the debt percentage of capital structure is increased to 80% of capital, the NPV increases by 33.63% to $421,578. IRR also experiences a 4.22% increase. Note the LCOE decreases with the increase in debt capital as a result of less upfront cash outflows at higher present value associated with higher debt. Increasing the debt, however, also increases the breakeven point to year 11. The lower debt scenario illustrates the significant decrease in NPV of 44.97% accompanied with a moderate increase in LCOE. However,

Table 8: Capital structure sensitivities of Komreddypalle PV plant

	Base Case	Higher Debt Case		Lower Debt Case	
		New Value	% Δ from Base	New Value	% Δ from Base
Debt %	70%	80%	14.29%	60%	-14.29%
NPV	$315,476	$421,578	33.63%	$173,610	-44.97%
IRR	17.28%	18.01%	4.22%	16.59%	-4.01%
LCOE	$0.14608	$0.14424	-1.26%	$0.14854	1.69%

decreasing debt capital decreases the breakeven point to year 9. From table 8, it is clear that the NPV and LCOE parameters are much more sensitive to decreases in debt capital than increases in debt capital. Similar to LCOE sensitivity with respect to total cost, this is due to the larger cash outflow in the present, which has a higher inherent present value. Depending on the investor and its financial priorities, it may be beneficial to lever projects higher or lower on a case by case basis.

Discount Rate Sensitivity Analysis

The financial model in the previous section discounted the project's levered cash flows using the levered cost of equity of 15.93%. This is one financial method to discount cash flows based on equity holders' economical expected rate of return derived from local market factors. Alternatively, the cash flows of the financial model can be discounted using their opportunity cost of capital. As previously discussed in this chapter, an investor can use the IRR of other investments to quantify their opportunity cost of capital. Altering the discount factor of a project drastically changes the financial outcomes. Therefore, it is important to explore the financial model results with a range of discount factors within a sensitivity analysis. Table 9 depicts the sensitivities of the financial outcomes with respect to the discount rate. This analysis assumes the investor has an opportunity cost of capital of 12.00% and 9.00% in two different cases.

Table 9: Discount rate sensitivities of Komreddypalle 5 MW PV plant

	Base Case (Levered)	12% Discount Case		9% Discount Case	
		New Value	% Δ from Base	New Value	% Δ from Base
Discount Rate	15.93%	12.00%	-24.67%	9.00%	-43.50%
NPV	$315,476	$1,663,280	427.23%	$3,395,186	976.21%
LCOE	$0.14608	$0.13319	-8.82%	$0.12330	-15.59%
LROE	$0.15156	$0.15585	2.83%	$0.16043	5.85%

When a discount rate of 12% is utilized in the financial model, the NPV rises by 427.23% to $1,663,280. Additionally, the LCOE is dramatically reduced by 8.82% with an LROE increase of 2.83%. When assuming a discount rate of 9.00%, the effects are even more dramatic with an NPV increase of 976.21% and an LCOE decrease with an LROE increase. This sensitivity analysis depicts the significant NPV sensitivity to the discount rate used. Furthermore, note that with decreasing discount rates, the contribution margin between LROE and LCOE increases significantly, which ultimately increases the value of the solar resource. In scenarios of a PV investment where the solar resource is classified as a marginal solar reserve, the effect of the discount rate should be taken into consideration. If reducing the discount rate increases the resource to solar reserve classifications, then the PV project must be analyzed on the basis of investor priority and opportunity cost.

Chapter 7

Conclusions on Resource-Reserve Analyses for Utility-Scale Solar Photovoltaic Investment in India

Restatement of Objectives

As the cost of solar photovoltaics continue to decrease, the technology is quickly becoming a viable large-scale electricity generation application approaching grid parity. As a result of the wide-spread available incentives for solar PV, independent power producers (IPPs) have been increasing as electricity generation investment opportunities arise. To accommodate this rise in investment opportunities, this report offers a new method for classification and quantification of the solar resource and solar reserves as they apply to utility-scale solar PV. This new system, adapted from the USGS, provides the foundation of solar resource economics upon which individuals, firms, and investors can make rationalized decisions on the allocation and PV electrical conversion of the solar resource. To analyze the feasibility of utility-scale PV investment in India, this report utilized this solar resource-reserve system in conjunction with regional-based economic and financial analyses to quantify the amount and value of the solar reserve for a real-world utility-scale PV investment opportunity.

Solar Resource-Reserve Classification System Applied to Photovoltaics

After providing an understanding of the technical factors behind the generation of electricity via PV technology, the solar resource economics for PV technology were introduced using the solar resource-reserve classification system. The solar resource is an outflow of energy from the sun, which is the solar resource’s stock. Similar to mining coal, the solar resource can be utilized by converting it into electricity. The solar resource can be measured or indicated using solar irradiance measuring instruments (i.e. pyranometers or pyrheliometers) or satellite mapping of solar irradiance. The quantity of the solar resource can be classified as a solar reserve, marginal solar reserve, or subeconomic solar resource, which indicates that conversion of the solar resource into electricity is entirely economically viable, marginally economically viable, or entirely uneconomical, respectively.

Solar resource conversion economic viability is determined by the levelized cost of electricity (LCOE), government incentives/policies, selling price of PV-generated electricity, and the quantity of PV-generated electricity demand. LCOE is affected by the costs associated with installing and operating the plant, the amount of generated electricity over the PV plant’s lifetime, and the discount rate used. Government incentives and policies are based on the regional government’s renewable policy initiatives. The selling price of PV-generated electricity is affected by market electricity rates, which are in turn affected by fuel costs, energy supply, and energy demand. Likewise, the quantity of PV-generated electricity demanded is dependent on avoidance of fuel costs, elasticity of electricity demanded, and energy constraints; this factor is interrelated to the selling price of PV-generated electricity. If these factors create a levelized selling price of PV electricity and government incentives sum (LROE) that is greater than the LCOE, conversion of the applicable solar resource is economically viable and is a solar reserve. If the LROE is approximately equal to the LCOE, the conversion of the applicable solar resource borders on economic viability and is a marginal solar reserve. If the LROE is less than the LCOE, the conversion of the applicable solar resource is not economically viable and is a subeconomic resource. Investment into a utility-scale PV plant should be undertaken if the converted solar resource is classified as a solar reserve. The investment may also be undertaken if the converted solar resource is classified as a marginal solar reserve depending on future outlook and risk preference of the investor.

Regional Resource-Reserve Factors of Photovoltaic Investment

The region in which the solar resource is measured or indicated affects the intensity and quantity of the solar resource. The location's position with respect to the sun establishes the relevant available solar resource. Declination angle of the earth with respect to the sun creates seasonal times of the year when the solar resource is stronger. Solar altitude and irradiance tend to increase during summer months when the declination angle is larger (for the Northern hemisphere). As solar altitude increases, the solar resource travels through less air mass, which increases the amount of the solar resource incident on the earth's surface. Solar PV arrays are tilted to maximize the module area with solar rays incident at a 0° angle, which maximize the convertible solar resource. Additionally, trackers are used to maximize the collection of the solar resource by orienting modules to follow (track) the sun as it passes through the sky throughout the day; this can increase the convertible solar resource significantly. Global horizontal irradiation (GHI) and direct normal irradiation (DNI) are the most commonly used measurements of the solar resource in units of kWh. India is exposed to a large average daily irradiation of about 4.75 to 6.00 kWh/m^2. The amount of the solar resource collectible by the solar modules is directly related to the amount of the solar resource that is convertible into electricity and can potentially be classified as a reserve.

To define a solar resource's capability of reserve classification, regional economic conditions with respect to PV technology were taken into consideration. Factors including the effects of electrical infrastructure, local electricity market, financial incentives, and costs were considered to determine the potential profitability of PV-generated electricity, and therefore, its economic viability. In order for large-scale PV system to create a solar reserve, an adequate electrical grid must be in place. While India's electrical infrastructure is less than ideal, suffering regional faults and power outages, it is sufficient for power generation offtake. Potential utility-scale PV generation plants form PPAs with electricity rates that compete with the local electricity market rates, which makes it crucial to understand the causes of end-user electricity pricing affects. About 59% of electricity is generated with coal-fired power plants and about 9% with gas. The electricity generator pricing system, based primarily on the Availability Base Tariff (ABT) and long-term contracts with Discoms/SEBs, reflects the coal and gas fuel costs associated with these power generation technologies. Hydropower also composes about 17% of the total power generation, which creates seasonal fluctuations in energy supply for areas with season-dependent hydropower installed capacities. As a result of hydropower generation and overall lack of installed capacity, the Indian electrical regions experience annual energy deficits that range from 4.57% to as high as 16.02%. This lack of energy supply places upward price pressure on end-user electricity prices, which translates to higher-rate PV generation PPAs. The inherent high electricity prices in India are about $0.10/kWh or higher (non-domestic users) and increase at an annual rate of over 10% per year. This places Indian grid-parity of PV solar resource conversion on a fast track as LCOEs of PV technology continue to decrease to a projected $0.15/kWh in 2018 while India's electricity prices continue to increase.

India offers beneficial incentives to utility-scale PV investors through the National Solar Mission (NSM) policy. The NSM aims to reach over 20,000 MW of installed PV capacity by 2022 through implementation of Feed-in-Tariff (FIT) and REC mechanisms for obligated entities to meet renewable power obligations (RPOs). Discoms/SEBs can meet RPOs by purchasing PV-generated electricity at an FIT determined by a reverse bidding process (depending on the state) or by purchasing RECs. While the solar RPO is scheduled to increase in the future, many state governments (e.g. Gujarat) have reneged on their RPOs, and only a few SERCs have actively enforced the RPOs via penalty charges. As a result of the lack of enforcement, RECs have traded at the floor price since June, 2013, and the market has become oversupplied by over 126,000 RECs. This represents a significant risk for investors looking to develop utility-scale PV using the FIT and REC mechanisms, and it should be accounted for in their investment analyses. However, the high selling price of electricity coupled with these incentives is capable of creating LROEs greater than the LCOEs of many utility-scale PV investment opportunities.

Solar Resource-Reserve Classification and Quantification of the Komreddypalle 5 MW PV Plant via Financial Analysis

To determine the economic viability and reserve of the solar resource for the real-world Indian utility-scale PV investment opportunity, this report utilized a discounted cash flows financial analysis to determine the NPV, IRR, LCOE, and LROE of the potential investment. The levered cost of equity and weighted average cost of capital (WACC) were used in order to discount the cash flows; the beta for these calculations was determined to be about 1.59 by averaging betas of comparable companies within the Indian PV electric generation market. The levered cost of equity of the relevant investor was determined to be about 15.93%, and when used in conjunction with a 70% debt capital structure with 12.5% interest, the WACC was determined to be about 11.78%.

With an annual GHI at the Komreddypalle 5 MW project site of about 2,000 kWh/m^2, the solar resource present on the 31.5 acres could be determined. The annual indicted solar resource incident on the land was about 255 million kWh (GHI). Given the 33,319 m^2 of tracking module surface area, about 188.3 million kWh incident on the land in areas where modules did not cover due to inverter space, inter-row spacing, shading constraints, and unused sunk cost land was classified as subeconomic solar resources. The indicated solar resource collected by the solar panels was about 81.0 million kWh (GHI on tracking surface area of modules), of which 71.3 million kWh were deemed subeconomic solar resources due to angle of incidence losses, efficiency of conversion, and expected electrical losses; the remaining 9,776,258 kWh is the total annual converted solar resource and is the amount of solar resource capable of solar reserve classification.

With a total installed cost of about $7.559 million, the financial analysis was completed using a PPA rate of $0.1167/kWh for the first 5 years, $0.125/kWh with a 2.5% annual escalation for years 6-10, followed by an annual escalation of 5% for years 11-25. Assuming an REC clearance at the floor price (~$155/REC) of about 20% to mitigate REC risk, the financial analysis was used to calculate the 70% levered discounted cash flows (discounted with the 15.93% levered cost of equity). The financial results were:

- NPV of $315,476
- IRR on equity of 17.28%
- Levered LCOE of $0.14608/kWh
- Unlevered LCOE of $0.13794/kWh (WACC discount rate used)
- LROE of $0.15156/kWh

With the indication of a positive NPV and a greater LROE than LCOE, the 9.776 million kWh of converted solar resource was deemed entirely economically viable, and therefore, was classified as a solar reserve. The total solar reserve quantity was equal to the total lifetime generation of the plant of 230.289 million kWh (refer to table 6 for complete solar reserve-resource classification).

A sensitivity analysis was conducted to note the NPV, IRR, and LCOE sensitivities associated with changes in total installed cost, capital structure, and discount rate. It was noted that total cost changes indicated significant NPV and LCOE sensitivities, and moderate IRR sensitivities. A total installed cost of about $7.912 million would be required to derive an NPV of $0. NPV proved to be highly sensitive to changes in capital structure with higher and lower debt percentage. Certain investors may choose to lever investments more or less depending on their financial priorities. Using lowered discount rates to represent lower opportunity costs of capital proved to increase the contribution margin (LROE – LCOE) significantly for the PV projects, which creates extreme increases to NPV. Potential PV projects with a marginal solar reserve should consider the effects of a lower discount rate to possibly drive the solar resource into solar reserve classification and measure opportunity cost against risk of the project investment.

Conclusions of the Solar Resource-Reserve Classification System and Utility-Scale PV Feasibility in India

The solar resource-reserve classification system presented and utilized in this report successfully provides the framework to rationally make utility-scale PV investment decisions. In addition, the system allows quantification of solar resources and reserves based on resource measurement technique and economic viability of solar resource conversion. The system allows for categorization of subeconomic solar resources incapable of economical conversion due to shading constraints, unused sunk cost land, angle of incidence losses, efficiency losses, and electrical losses. Investors can use the solar resource-reserve system to effectively justify investments into potential power generating PV assets. This report successfully utilizes the system to analyze the feasibility of utility-scale PV investment in India based on solar resource-reserve economic and financial analyses. The application of the system proved the solar reserve in India to be potentially very large as evidenced by the 5 MW Komreddypalle project. However, the government will continue to play a very important role in the future of Indian solar reserves. Enforcement of RPOs must be emphasized to sustain their FIT, REC, and other incentive mechanisms from their policy implementations that are crucial to supporting utility-scale PV in India. While PV projects utilizing the Indian FIT or REC mechanisms are often considered not bankable, the energy demand in India coupled with a lack of energy supply put significant upward price pressure on end-user electricity prices. Investors must account for the risk associated with lack of government policy enforcement, but the significant increasing trends in electricity price effectively serve to mitigate this risk. This fast-tracked grid parity coupled with re-amplified government support has the ability to create an exponential increase in the Indian solar reserve for utility-scale PV in the near future.

Appendix A

Example of Solar Photovoltaic System Design

The most effective manner of providing a background in the solar design process of array-inverter matching is via an example. This example uses the following assumptions:[69]

- A developer is designing a 6 kW solar PV system for use in Williamsport, Pennsylvania
- Williamsport has a minimum ambient temperature of -25°C and a maximum ambient temperature of 38°C
- The design utilizes a Fronius IG Plus 6 kW inverter
- The design utilizes an array of Solon XT 285 W modules

The inverter and module pictures and specifications sheets are included in figure 30 and tables 10 and 11, respectively.

Figure 30: Fronius IG Plus Inverter and Solon Black XT 285W Module[70]

Table 10: Fronius IG Inverter Specifications[70]

INPUT DATA	Fronius IG Plus 60 V-1
DC maximum power at cos ϕ=1	6,320 W
Max. array short circuit current	41.3 A
Max. input current	27.5 A
Max. input voltage	600 V
MPP voltage range	230 - 500 V

Table 11: Solon Black XT Module Specifications[71]

Electrical specifications – typical (STC)					
STC (Standard Test Conditions): 1,000 W/m², 77 ± 3.6°F (25 ± 2°C), AM 1.5					
Capacity rating	P_{max}	295 Wp	290 Wp	285 Wp	280 Wp
Module efficiency		14.90 %	14.65 %	14.39 %	14.14 %
Rated voltage	V_{mpp}	35.80 V	35.60 V	35.40 V	35.20 V
Rated current	I_{mpp}	8.26 A	8.16 A	8.06 A	7.96 A
Open circuit voltage	V_{OC}	44.50 V	44.23 V	43.96 V	43.69 V
Short circuit current	I_{SC}	8.66 A	8.59 A	8.51 A	8.44 A
Series fuse rating	I_R	15 A	15 A	15 A	15 A
Maximum system voltage	V_{DC}	600 V	600 V	600 V	600 V

The first step of the design process is to determine the maximum and minimum voltages that the modules can experience in the variable temperature conditions of the system's location (note: the effect of temperature on module performance is explained in greater detail in chapter 3). The modules will experience a maximum voltage at the lowest temperature experienced at the location (T_{min}), which is -25°C in this example. The module temperature coefficient (T_C) is used to calculated the change in voltage with respect to change in temperature from standard conditions (25°C); Solon specifies its temperature coefficient as -0.36%/°C. Equations 7 and 8 are used to calculate the maximum voltage:

$$V_{max} = V_{OC} + (T_{min} – 25\ ℃)(T_C)(V_{OC}) \quad (7)$$

$$V_{max} = (43.96\ V) + ((-25\ ℃) – 25\ ℃)(-0.0036/℃)(43.96\ V)=51.87\ V \quad (8)$$

This equation is formed by using the 285 W module specifications shown in table 11. The open circuit voltage of 43.96 V is adjusted using the temperature coefficient and the change in temperature to find a maximum voltage of 51.87 V per module. Using the inverter specifications shown in table 10, the maximum input voltage that the inverter can accept is 600 V. Therefore, if all of the modules are operating at maximum voltage, the most the inverter can accept is 11 modules (*600V/51.87V = 11.56 =>11*) per string. The minimum module voltage occurs at the highest temperature experienced at the location (T_{max}), which is 38°C in this example. Similarly, equations 9-10 are utilized to calculate the minimum voltage:

$$V_{min} = (V_{mpp}) + (T_{max} – 25\ ℃)(T_C)(V_{mpp}) \quad (9)$$

$$V_{min} = (35.40V) + (38 – 25\ ℃)(-0.0036/℃)(35.40V) = 33.74V \quad (10)$$

The rated voltage of the module of 35.40 V (shown in table 11) is adjusted using the temperature coefficient and change in temperature to find the minimum voltage of 33.74 V per module. The inverter specifications in table 10 indicate that the minimum input voltage is 230 V. To make a conservative estimate, 120% of the minimum input voltage—276 V—is used in the following calculations so that the system maintains a voltage that is safely in the maximum power output range (e.g. 230V-500V, shown in table 10). If all modules are operating at the minimum voltage of 33.74 V, the least amount of modules the inverter can accept is 9 modules (*276V/33.74V = 8.18 => 9*) per string. According to these minimum and maximum voltages, each string must have between 9 and 11 modules. The system power requirement is at least 6 kW. With each module contributing 285 W of power, the system must have at least 21 modules. Given that a single string can only contain a maximum of 11 modules, the system must have multiple strings connected in parallel with the same voltage to accommodate the power requirement; because each string must have the same number of modules, the array must consist of at least 22 modules. The best configuration that conforms to these numbers is a PV array of 2 strings with 11 modules per string. This system will have an overall power rating of 6.27 kW, which remains safely under the maximum 6,320-W input of the inverter specifications (table 10). In addition, the 2-string system will only provide a total short circuit current input of 17.02 A, which is also safely below the 41.3-A maximum short circuit current input of the inverter.

Appendix B

Indian Currency

The currency of India is the Indian Rupee (INR). The financial chart of the USD to INR foreign exchange from April, 2013 to April 2014 is shown in figure 31.While the INR was subject to volatility around September, 2013, it has since then settled at an average price of about INR 60 to USD 1.[72] The current INR value (as of March 30, 2014) is INR 59.88 to USD 1.[72] As such, this report utilizes a value of INR 60 to USD 1 for conversions. Note that INR is denoted by "Rs." in this report.

Figure 31: Chart of INR to USD 1 from April 2013 to April 2014[72]

Appendix C

Excel Financial Modeling

The financial model for years 11-25 of the levered Komreddypalle 5 MW PV plant are shown in figures 32 and 33. Indian taxes imposed on PV power plants, such as the Komreddypalle 5MW plant, typically only consist of the Minimum Alternate Tax (MAT). The MAT is a rate of 20.01% on Profit Before Tax (PBT). The Indian corporate tax is 32.45%; however, a PV power plant is capable of claiming 100% accelerated tax depreciation in the first year of the project's operation. This accelerated depreciation benefit effectively shields the PV asset from the corporate tax throughout its 25 year lifetime. Note that the depreciation values shown in figures 26, 32, and 33 are the Book Depreciation values (as opposed to the accelerated Tax Depreciation) at a rate of 15.33% on the asset's depreciable value. Instead of paying the corporate tax rate, the MAT is paid when the asset's cumulative PBT is positive.[10,43]

For example in figure 26, the Komreddypalle plant owes $0 in income tax until year 7. In the first 3 years, the project returns negative PBT values. These negative PBT values carryover to future years of the project. The first 3 years of negative values sum to a cumulative PBT of -$638,217. The positive PBT values in years 4 through 7 turn the cumulative PBT to a positive value by year 7. Therefore, year 7 is the year that the plant begins paying the 20.01% MAT on the year's PBT.[10,43] As the cumulative PBT never becomes negative thereafter, years 7 to 25 include an Income Tax equivalent to 20.01% of the relative year's PBT.

Year	11	12	13	14	15	16	17	18	19	20
Gross Electricity Production	9,298,298	9,251,807	9,205,547	9,159,520	9,113,722	9,068,154	9,022,813	8,977,699	8,932,810	8,888,146
Aux Consumption	46,491	46,259	46,028	45,798	45,569	45,341	45,114	44,888	44,664	44,441
Transmission Loss	46,491	46,259	46,028	45,798	45,569	45,341	45,114	44,888	44,664	44,441
Net Production	9205315	9159288	9113492	9067925	9022585	8977472	8932585	8887922	8843482	8799265
PPA Price/kWh	$ 0.1449	$ 0.1521	$ 0.1597	$ 0.1677	$ 0.1761	$ 0.1849	$ 0.1941	$ 0.2039	$ 0.2140	$ 0.2247
Total PPA Sale	$ 1,333,624.08	$ 1,393,303.76	$ 1,455,654.11	$ 1,520,794.63	$ 1,588,850.19	$ 1,659,951.23	$ 1,734,234.05	$ 1,811,841.02	$ 1,892,920.91	$ 1,977,629.12
REC Price/MWh	$ 38.75	$ 38.75	$ 38.75	$ 19.38	$ 19.38	$ 19.38	$ 19.38	$ 19.38	$ 9.69	$ 9.69
RECs Cleared	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Total REC Sale	$ 71,338.75	$ 70,951.25	$ 70,602.50	$ 35,126.88	$ 34,952.50	$ 34,778.13	$ 34,603.75	$ 34,429.38	$ 17,127.50	$ 17,040.31
Total Electricity Sales	$ 1,404,962.83	$ 1,464,255.01	$ 1,526,256.61	$ 1,555,921.50	$ 1,623,802.69	$ 1,694,729.36	$ 1,768,837.80	$ 1,846,270.40	$ 1,910,048.41	$ 1,994,669.43
O & M	$ 159,585.21	$ 168,713.48	$ 178,363.89	$ 188,566.31	$ 199,352.30	$ 210,755.25	$ 222,810.45	$ 235,555.21	$ 249,028.97	$ 263,273.43
General & Administrative Expenses	$ 14,049.63	$ 14,642.55	$ 15,262.57	$ 15,559.22	$ 16,238.03	$ 16,947.29	$ 17,688.38	$ 18,462.70	$ 19,100.48	$ 19,946.69
Insurance premium	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06
Salary & Wages	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00
Operating Income	$ 1,203,318.93	$ 1,252,889.92	$ 1,304,621.08	$ 1,323,786.91	$ 1,380,203.29	$ 1,439,017.75	$ 1,500,329.90	$ 1,564,243.42	$ 1,613,909.89	$ 1,683,440.25
Book Depreciation	$ 203,609.75	$ 172,396.37	$ 145,968.01	$ 123,591.11	$ 104,644.59	$ 88,602.58	$ 75,019.80	$ 63,519.27	$ 130.90	$ -
Loan Interest	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Profit Before Tax	$ 999,709.19	$ 1,080,493.54	$ 1,158,653.07	$ 1,200,195.80	$ 1,275,558.70	$ 1,350,415.17	$ 1,425,310.10	$ 1,500,724.15	$ 1,613,778.99	$ 1,683,440.25
Income Tax	$ 200,041.81	$ 216,206.76	$ 231,846.48	$ 240,159.18	$ 255,239.30	$ 270,218.08	$ 285,204.55	$ 300,294.90	$ 322,917.18	$ 336,856.39
Profit After Tax	$ 799,667.38	$ 864,286.79	$ 926,806.59	$ 960,036.62	$ 1,020,319.40	$ 1,080,197.09	$ 1,140,105.55	$ 1,200,429.25	$ 1,290,861.82	$ 1,346,583.85
Add Back Depreciation	$ 203,609.75	$ 172,396.37	$ 145,968.01	$ 123,591.11	$ 104,644.59	$ 88,602.58	$ 75,019.80	$ 63,519.27	$ 130.90	$ -
After Tax Operating Income	$ 1,003,277.13	$ 1,036,683.16	$ 1,072,774.60	$ 1,083,627.73	$ 1,124,964.00	$ 1,168,799.67	$ 1,215,125.35	$ 1,263,948.52	$ 1,290,992.72	$ 1,346,583.85
Increase in Term Loan										
CapEx and Land Loan Principal Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Cash Flow	$ 1,003,277.13	$ 1,036,683.16	$ 1,072,774.60	$ 1,083,627.73	$ 1,124,964.00	$ 1,168,799.67	$ 1,215,125.35	$ 1,263,948.52	$ 1,290,992.72	$ 1,346,583.85
Discounted Cash Flow	$ 197,363.44	$ 175,912.22	$ 157,022.76	$ 136,816.48	$ 122,518.34	$ 109,801.10	$ 98,467.26	$ 88,349.55	$ 77,840.01	$ 70,035.25

Figure 32: Komreddypalle 5MW PV plant financial model (years 11-20)

Year	21	22	23	24	25
Gross Electricity Production	8,843,705	8,799,487	8,755,489	8,711,712	8,668,153
Aux Consumption	44,219	43,997	43,777	43,559	43,341
Transmission Loss	44,219	43,997	43,777	43,559	43,341
Net Production	8755268	8711492	8667935	8624595	8581472
PPA Price/kWh	$ 0.2360	$ 0.2478	$ 0.2602	$ 0.2732	$ 0.2868
Total PPA Sale	$ 2,066,128.02	$ 2,158,587.25	$ 2,255,184.03	$ 2,356,103.52	$ 2,461,539.15
REC Price/MWh	$ 9.69	$ 9.69	$ 9.69	$ -	$ -
RECs Cleared	20%	20%	20%	20%	20%
Total REC Sale	$ 16,962.81	$ 16,875.63	$ 16,788.44	$ -	$ -
Total Electricity Sales	$ 2,083,090.84	$ 2,175,462.88	$ 2,271,972.47	$ 2,356,103.52	$ 2,461,539.15
O & M	$ 278,332.67	$ 294,253.30	$ 311,084.59	$ 328,878.62	$ 347,690.48
General & Administrative Expenses	$ 20,830.91	$ 21,754.63	$ 22,719.72	$ 23,561.04	$ 24,615.39
Insurance premium	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06	$ 11,339.06
Salary & Wages	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00	$ 16,670.00
Operating Income	$ 1,755,918.20	$ 1,831,445.89	$ 1,910,159.10	$ 1,975,654.80	$ 2,061,224.21
Book Depreciation	$ -	$ -	$ -	$ -	$ -
Loan Interest	$ -	$ -	$ -	$ -	$ -
Profit Before Tax	$ 1,755,918.20	$ 1,831,445.89	$ 1,910,159.10	$ 1,975,654.80	$ 2,061,224.21
Income Tax	$ 351,359.23	$ 366,472.32	$ 382,222.84	$ 398,637.03	$ 415,744.11
Profit After Tax	$ 1,404,558.97	$ 1,464,973.57	$ 1,527,936.26	$ 1,577,017.77	$ 1,645,480.10
Add Back Depreciation	$ -	$ -	$ -	$ -	$ -
After Tax Operating Income	$ 1,404,558.97	$ 1,464,973.57	$ 1,527,936.26	$ 1,577,017.77	$ 1,645,480.10
Increase in Term Loan					
CapEx and Land					
Loan Principal Payment	$ -	$ -	$ -	$ -	$ -
Net Cash Flow	$ 1,404,558.97	$ 1,464,973.57	$ 1,527,936.26	$ 1,577,017.77	$ 1,645,480.10
Discounted Cash Flow	$ 63,012.60	$ 56,691.95	$ 51,003.62	$ 45,408.43	$ 40,869.26

Figure 33: Komreddypalle 5MW PV plant financial model (years 21-25)

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EDUCATION

The Pennsylvania State University Anticipated Graduation
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B.S. in Energy, Business and Finance
B.S. in Energy Engineering
Minor: Environmental Engineering

Schreyer Honors College – Honors Thesis: "Resource-Reserve Economic and Financial Analyses of Utility-Scale Solar Photovoltaic Investment in India"
Thesis Supervisor: Dr. Antonio Nieto

EXPERIENCE

Halo Energie Pvt Ltd – AP, India *Financial and Investment Analysis Advisor* 2012-present

- Assist Halo Energie in Independent Power Producer (IPP) corporate financial structuring
- Generate financial models for potential utility-scale solar photovoltaic power plants; conduct investment and feasibility analyses for potential power projects
    - Komreddypalle, AP, India – 5 MW Solar PV Ground-Mounted
    - Tirupati, AP, India – 5 MW Solar PV Ground-Mounted
    - Dimapur, Nagaland, India – 10 MW Solar PV Ground-Mounted
    - Berlin, Germany – 1.6 MW Solar PV Rooftop

General Electric – Aero Services, Houston, TX *Supply Chain FMP Intern* summer 2013

- Analyzed over 2500 manual journal entries (MJE) and identified a 29% reduction opportunity
- Developed an MJE tracker to automatically analyze a total year of MJE data
- Compiled spreadsheet of 73 Quarter close activities to develop standardized closing rigor, aide in alignment amongst global supply chain segments, and improve FP&A coordination
- Conducted modified Fixed Asset Register (FAR) review and validated $3.42 million in original book value assets
- Delivered hour presentation to Aero Services CFO and managers on MJE reduction, quarter close, and FAR streamlining

Range Resources – Marcellus Division, Canonsburg, PA *Land Intern* summer 2012

- Prepared project feasibility analysis, leasing strategy, and drilling plan for 9,200-acre potential natural gas development at Pittsburgh International Airport (PIT)
- Developed customized report for financial analysis of PIT lease bonus and royalty payments
- Delivered 20 minute feasibility analysis presentation to business sector executive staff

- Performed field operations with land agents to obtain oil and gas leases, conduct notifications, supervise reclamations, and resolve damage complaints

The Reinvestment Fund – Philadelphia, PA *Housing Lending Intern* summer 2011

- Created self-evaluating Statement of Cash Flows for customer financial database, enhancing TRF's loan management processes
- Evaluated outstanding housing loans and completed assessment of customer financial health
- Optimized and streamlined customer financial database

SunPower Builders – Collegeville, PA *Public Relations Intern* summer 2010

- Organized lobbying activities of over 25 solar businesses for bill that would enhance solar business climate; coached business executives on talking points and facilitated meetings

LEADERSHIP

Footb(ALZ)stars – Gladwyne, PA *Co-founder and Vice President* 2011- present

- Created annual flag football tournament in Greater Philadelphia to raise funds and awareness for Alzheimer's disease.
- Donated total of $12,000 to Alzheimer's association
- Delegated responsibilities to Board of Directors, coordinated with high schools, sponsors, insurance company, and hosting sports complex

Sigma Pi Fraternity – State College, PA *Head THON Chair* 2011-2012

- First leadership in over 5 years to successfully raise over $100,000

HONORS AND AWARDS

Earth and Mineral Sciences College Student Marshal (Spring, 2014)
Dean's List (Fall 2009 – Fall 2013)
John and Willie Leone Family Undergraduate Scholarships (2012/2013 and 2013/2014)
Sarma V. and Rama Pisupati Endowed Scholarship in Energy Engineering (2012/2013)
John and Elizabeth Holmes Teas Scholarship (2011/2012)
Virginia S. and Philip L. Walker Jr. Enrichment Scholarship (2010/2011)
The Hess Scholarship (2010/2011)
The President's Freshmen Award (Spring, 2010)