A CAPACITY PLANNING METHODOLOGY FOR RURAL INDIA:
AN APPLICATION TO GRID-CONNECTED PHOTOVOLTAICS

by

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ABSTRACT

India projects a staggering demand for power generation capacity in the next few decades to keep up with industrialization and development. A significant portion of this growth will come from predominantly rural areas. Because of poor revenue generation in the agricultural sector, State Electricity Boards (SEBs) lack the economic incentives to build capacity for rural areas. This has led to a progressive degradation of the quality of power in rural areas and of the financial viability of SEBs. At the same time, foreign and private investment in large-scale power plants has been increasing rapidly, without a rigorous framework to study the efficient allocation of resources, the environmental consequences of different investment paths or the appropriate solutions to meet energy needs. No methodology currently exists for capacity planning in the rural context to guide policy making.

This thesis develops a methodology for planning capacity expansion for an agricultural region of India employing distributed photovoltaics (PVs). The choice of technology is motivated by its environmentally benign nature and the benefits of distributed generation. The failures of traditional capacity planning in the Indian context are highlighted. Methodologies are developed to estimate load and quantify distribution losses with limited data. A production cost model based on this new methodology incorporates the high distribution losses, models the uncertainty of solar insolation and calculates the avoided costs of PVs in the state of Haryana. The thesis also discusses the most suitable technical configuration for PVs, the pricing and ownership structure and the potential for PVs to achieve cost-competitiveness.

The results of the analysis show that the solar resource potential coupled with the high cost of power delivery along poor T&D systems render the value of photovoltaics to be high relative to other PV applications. Overall, the most suitable configuration of PVs is shown to be single, privately owned, plants on each distribution feeder. In practice, the value of PVs will be offset by the high cost of their configuration and their sub-optimal performance when integrated into the power distribution system. From a policy perspective, PVs do not, however, eliminate the inefficiencies in the power system. SEBs need to focus on demand-side issues more closely and undertake cost-based tariff reform before considering further capacity expansion. A critical conclusion of this thesis is that the value of PVs will decrease significantly when these distortions in demand are eliminated.

Thesis Supervisor: Richard D. Tabors, Ph.D.
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Acknowledgments

This thesis is dedicated to my two nephews, Adrian and Neil

You could drive me into nervous, nostalgic frenzy with the mention of my thesis nemesis: "data". This work would have been impossible and meaningless without the information provided to by my friends in TERI, New Delhi, and first thanks must go to them. I am grateful to Sharmila Bharatan, B. Rajsekhar, Meena Srikumar, and Dr. Mukherjee for their transcontinental assistance. The seed for this work was provided by Dr. Ajay Mathur during my summer internship with TERI. Unbeknownst to him, I managed to achieve my goal of writing a thesis on the energy sector of India primarily as a result of my meaningful internship with him.

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This thesis has been the culmination of all that I have learnt at MIT, and I must acknowledge all the friends that contributed to that learning experience. They are all, for the most part, bozos. Nevertheless, I truly appreciate Mort's indefatigable willingness to help. Judy's company in class and her inexhaustible supply of relevant articles made my research that much more meaningful. Mark's superlative black bean soup put me into overdrive on the homestretch of my thesis. Uday was the vital Indian connection who identified with my concerns and ideals, and served as my reality check. Last and certainly not least, my friendship with Shanthi was invaluable to me throughout school.

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1. Introduction

The growth of energy demand in developing countries is escalating. If current trends in population growth and energy use continue, population will double, and the energy demanded per person will treble by the year 2050. Several protectionist developing economies have finally succumbed and opened their doors to foreign investment, with an apparent emphasis on growth at any cost. With current energy production patterns, the environmental impacts on the earth fifty years from now can prove devastating. India and China, who together constitute 40% of the world's population, meet demand growth with coal contributing 60% and 76% to energy production respectively. This percentage can rise in the future, given the relative abundance of coal and the uncertainty in future oil prices.

The worrisome characteristic of these trends is their rapidity. Growing concern for the environment calls for a serious evaluation of the sustainability of the technologies of energy production and a stronger emphasis on the commercialization of non-polluting energy sources, such as solar and wind energy. Historically, research in renewable energy in developing countries has focused on non-electric use of energy for rural applications or stand-alone electric systems. Although a small number of grid-connected installations have been demonstrated, the rate of penetration of commercialized, reliable applications has been minimal. Price, and complexity of use and deployment, have impeded the large-scale application of renewables. For the case of photovoltaics, arguably price is the only real hurdle. Given the inevitable acceleration of energy demand in the future, there is a chance now to capitalize on the potential economies of scale that can result if manufacturing processes of renewable technologies can be given an impetus. However, to induce this growth, a justifiable case for the potential cost-effectiveness and viability of these solutions has to be made. This has to be supported by sound, comprehensive technical and policy analyses of these solutions that take into account the choice of technologies best suited to local conditions, technical feasibility and practicality issues, the appropriate siting and sizing of installations, and the consistency of these solutions with international and domestic policy directives.

A rigorous economic and policy analysis of capacity planning with a significant penetration of intermittent generation has never been done for India. Because of the unique characteristics of the Indian power sector, traditional approaches to capacity planning fail to provide an appropriate framework for analysis for capacity expansion. This thesis will explore these failures, and develop and simulate a new methodology for capacity planning in agricultural regions of India with a significant penetration of intermittent generation. The main contribution of this methodology is to incorporate the high level of losses in production cost planning, as well as to model the uncertainty in intermittent generation. An important outcome of this approach is to quantify what is only qualitatively known among informed circles to be the unusually high distribution losses in some agricultural regions. Most government publications quote conservative estimates of distribution losses. Analyses of rural areas lack reliable, detailed data on load patterns and power quality. In light of this limitation, methodologies are developed to estimate agricultural load patterns and distribution losses with the use of limited data.

This thesis focuses on grid-connected photovoltaics as a choice of intermittent generation technology. It investigates the claim that grid-connected photovoltaics offer a clean alternative for capacity expansion to meet growing, rural energy demand (dominated by irrigation) in electrified regions of India. Intuitively, the use of solar energy for electricity in these regions seems attractive because of the coincidence of the high daytime energy demand for irrigation with periods of high solar intensity. This is compounded by the high technical line losses on the lengthy, low-quality distribution networks in rural regions, which render the cost of providing electricity from centralized locations very high. Furthermore, rural regions that lie close to urban centers fall victim to constant load shedding, and as a result they usually suffer significant power deficits and operate at a high load factor. Generation from newly capacity at centralized locations tend to be absorbed by the high-growth urban centers, thereby offering little benefit to meet rural energy needs.

Based on the methodologies developed, a simulation of the power sector in Haryana calculates the effective avoided costs of PVs in rural Haryana. The analysis focuses on the district of Sonepat in Northern Haryana on the outskirts of the Indian capital, New Delhi. This region exhibits all the features described above, and characterizes many agricultural regions in India. It has been chosen for the purpose of providing a concrete framework for analysis, thereby allowing a more accurate calculation of distribution losses than done before.

In addition to developing and using an appropriate methodology for calculating the value of PVs, several policy and institutional issues that determine the feasibility and suitability of deploying PVs in rural India are explored. This policy analysis proceeds along two separate paths. The first examines the factors that will attract PV investors to India. This includes an analysis of the potential for the world PV market to attain a price that would render them competitive in India, along with the institutional and tariff structure that state governments in India should provide to investors. The other perspective looks at the prudence of deploying PVs to reduce the supply deficit in the rural power sector. It suggests that tariff reforms are necessary to control demand before capacity expansion for rural areas should even be considered.

Chapter two introduces the political and economic climate in India today. The structure of the energy sector, the government's position on non-conventional energy and the recent efforts to induce foreign participation in energy expansion will be discussed in order to lay the foundation for the analysis. The region of Sonepat, Haryana will be introduced and described. The chapter will also explore the extent to which grid-connected photovoltaics in the context presented here can have an impact on energy demand on a nation-wide basis.

Chapter three briefly describes traditional capacity planning methods and the conventional treatment of intermittent generation. The assumptions that underlie a least cost planning approach are explicated. The unique characteristics of the rural power sector and the agricultural consumer in India are then introduced in detail and analyzed within the context of traditional capacity planning. The failures of such an approach are highlighted, along with justifications for the development of a new methodology. Specifically, the impact of a severely supply-constrained sector along with the difficulty of planning without a long run marginal cost approach are analyzed. Several benefits of intermittent generation that often do not enter decision making processes, such as T&D and environmental benefits, are discussed and applied to the Indian context.

Chapter four develops and applies a new methodology for analyzing the economic benefits of intermittent generation based on the arguments developed in the previous chapter. The most important contributions in this methodology are the incorporation of T&D losses in the production cost simulation and the modeling of uncertainty in solar insolation. Methodologies for estimating agricultural load patterns in the absence of load data and for calculating technical losses in distribution systems are also developed. All the pieces of the methodology are then put together and applied to the case of Haryana in a production cost model that simulates a least-cost capacity expansion plan. The Monte Carlo method is used to model uncertainty in solar insolation. Numerical results are obtained for the break even cost of grid-connected photovoltaics in rural Haryana. The sensitivity of avoided costs to the power factor in the distribution system is analyzed, since it contributes significantly to distribution losses.

Chapter five studies the policy issues surrounding the promotion, pricing and suitability of grid-connected PVs. The results of the economic analysis are placed in a realistic context, from the perspective of a PV investor and that of a policy maker in India. Price projections of the PV market, and possible ownership and management structure for PV systems are suggested. The viability of the assumptions necessary for capacity expansion with PVs are challenged. These assumptions include the presence of incentives for capacity expansion in rural areas, and certain operational requirements arising from the optimal configuration of PV systems. The flip side to the supply deficit problem of demand management is explored, and suggested as a more appropriate target for a solution.

The appendices contain the engineering analyses undertaken for various components of the analysis. They include: an application of optimization techniques to identify the optimal locations and sizes of PV installations on a distribution system that would minimize losses; a detailed description of the solar insolation conversion model; an analytic solution to calculating the load carrying capacity of an intermittent source of power; a diagrammatic representation of the software developed to perform the production cost simulation; a description of the financial calculations embedded in the production cost model.

2. Background and Overview

2.1 The Indian Power Sector

India is the largest democracy in the world. In another thirty years it is also likely to be the most populous country with 1.4 billion people. India dominates the Indian subcontinent in area, spanning from 8° 4' to 37° 6' latitude above the equator with a land area of 3.28 million sq. km. It is a resource-rich country, with every possible geographic terrain falling within its boundaries. Lined by mountains in the North and along its eastern and western coasts, much of the land surface within India has a plateau-like character, with extensive plains. The Indo-Gangetic belt in Central India and the Deccan Plateau in the South contain mineral-rich soil, bathed by an abundance of rivers from the Himalayas and Central Highlands respectively. It is therefore no surprise that over sixty-five percent of employed Indians still engage in agriculture, and over eighty percent of Indians live in rural regions.

India is a developing economy, with starkly dichotomous economic characteristics. India achieved impressive results in agricultural production in the 70s, and claims to have achieved self-sufficiency in food production. It also has made tremendous progress in industrial and high-tech development. India today is the 20th largest economy in the world, measured in gross domestic product. However, these statistics belie the character of what constitutes the bulk of India; over 500,000 villages with a rural population plagued by malnutrition, low literacy and life expectancy, poor agricultural productivity that is still very dependent on the monsoons, and an overall per capita income of barely $300.

Since gaining independence from Britain in 1947, India has consistently followed a socialist path of industrialization, with the state owning and taking responsibility for the major infrastructural industries of power, communications, roads, critical resources (coal, steel, petroleum products and crude oil), and transportation. Its economic policies over the past four decades strongly echo the principles of self-reliance and protectionism. Today, the very infrastructural industries that the state deemed essential for the country and sought to protect by taking public ownership of are poorly managed, and have been unable to provide quality goods and services to all but the metropolitan centers of the country.

The pattern of growth in the past two decades project a change in the demographics of the future. Urbanization and industrialization have accelerated significantly, and culminated in the privatization and liberalization reforms of 1991. As in most privatization schemes in developing countries, growing disappointment with the financial performance of public enterprise, low productivity, and the sheer inability of the state to cope with growth motivated this reform process. The government essentially opened up the Indian market to foreign investment and ownership, thereby eliminating the only remaining hurdle to rapid economic growth. The first industries to participate in these schemes were in fact infrastructural industries, specifically power and telecommunications. The economic and policy initiatives reflect a greater emphasis placed on urban, rather than rural development.

The political climate in India today is particularly sensitive to foreign participation in private enterprise because of the ideological differences between competing political parties viz. a viz. nationalist sentiments. Foreign investors tend to be wary of newly emerging markets with unstable political climates, or with policies averse to foreign investment. The early 90s saw a secular, progressive party that dominated Indian politics almost entirely since independence institute long overdue reforms to encourage foreign participation. This political atmosphere, coupled with attractive economic incentives, attracted over $7 billion dollars in Foreign Direct Investments (FDI) over a span of four years. However, the Congress party has gradually relinquished its stronghold over the populace, and instability once again threatens to plague India's political future. The Congress party has suffered several defeats in state elections to a nationalist party, the Bharatiya Janata Party (BJP). In the state of Maharashtra, an affiliate party of the BJP has placed a major foreign power project involving the American power company Enron on hold. The outcome of this project can result in a drastic domino effect, since it is the first foreign collaboration in the power sector to have progressed from the proposal phase to the phase of implementation.

2.1.1 *Energy Resources and Demand Growth*

The structure of energy consumption mirrors closely the demographics of an economy, and its growth serves as a good indicator of future economic trends. The rural nature of India's population is reflected in its per capita commercial energy consumption, which is only one eighth of the world average, despite the fact that it is among the top 20 consumers of commercial energy. One third to a half of India's energy needs are provided by traditional biomass fuels. Solid fuels contributed 67.7%, while electricity accounted for a meager 3.8% of energy sources in 1988. Of this, industry consumed over 50% of electricity generated, while agriculture consumed only 9%[1].

The growth in commercial energy, and especially electricity, indicate the rapid industrialization and commercialization taking place. Electricity demand has been growing annually at about 9%, while industrial output rose at an annual rate of 6.3% in 1993-94. Of this, industry absorbed 38% of electricity demand, while the relative share of agriculture increased to 28%[2]. Since liberalization in the early 90s, the rate of electricity demand growth in the industrial and commercial sectors have exceeded that of agriculture. This thesis is concerned with the small portion of overall energy demand growth that constitutes agricultural demand for electricity.

2.1.2 *Irrigation and Electric Power*

One of the reasons for the increase in power consumption in the agricultural sector is the increased mechanization of irrigation, which constitutes one of the major agricultural activities in India. India receives too much rainfall in certain places, and too little in others, such that irrigation plays in important role in agricultural productivity. Rain also falls only during the monsoon season, which lasts only a few months. As of 1992-93, India has met only 71.5% of its total irrigation potential. In the state of Haryana alone, an untapped potential of a million hectares of irrigation still exists[3].

From the several manual and mechanical methods of irrigation used, electric pumps are the most popular and from the perspective of farmers both financially and economically preferable where

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[1]World Resources, 1994-95

[2]Eighth Power Plan Program 92-93 to 96-97, Dept. of Power, Government of India, 1991

[3]Statistical Outline of India, 1994-95, Pg 64

power is available[4]. This judgment is distorted by the subsidies afforded to electric power in rural areas, both for the purchase of equipment and electricity. Methods involving manual or animal labor do still exist, but are losing popularity. Renewable methods using non-electric energy, such as wind-powered deep-well pumps, require local expertise to maintain and set up, and do not give farmers flexibility in operating the pumps at their will. Diesel generators are a popular source of electrical energy, because of their independence from grid availability and portability. Government policies usually affect the choice between grid power and diesel fuel by subsidizing one type of power versus another, or by imposing taxes on the use of diesel fuel. The quality of power also indirectly depends on government policy, since investments in transmission and distribution can most often improve power availability in rural areas.

The poor quality of grid power adversely affects productivity in areas that depend on electricity for irrigation. Power availability often does not coincide with times of need, and constant disruptions and low voltages often prevent operation even during hours of availability. Given this conflict between irrigation needs and power availability, electricity generated specifically catering to local needs from renewable sources would benefit both the needs of farmers and improve the quality of power available to them.

2.1.3 Power Sector Overview

Despite being barely 4% of total energy output, electricity generation in 1993-94 amounted to 323.3 million kWh from an installed capacity of 76,718 MW. Roughly 60% of this comes from coal, with an additional 26.5% from hydro power. Domestic coal production has been steadily increasing, along with an increase in coal's share of electricity generation. With total electricity demand growing at 9% a year, an increase in capacity of 19,108 MW is envisaged in the Eighth Five-year Plan, ending in 1996-97[5]. In this period, supply is expected to fall short of peak demand by around 20%, with a Plant Load Factor (PLF) of 61%.

In order to bridge this enormous gap in supply and demand, Indian financial institutions would have to provide capital for capacity expansion at a rate far greater than they possibly could. Further, mobilization of capital commensurate with growing demand would also be very

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[4]Kahnert F. et al., "Groundwater Irrigation and the Rural Poor: Options for Development in the Gangetic Basin", Pg 24

[5]"Power target for 1994-95 raised", Hindustan Times, New Delhi

difficult. Hence, attractive incentives have been offered to private and foreign investors for power projects in the liberalization efforts of the early 90s. Of the 19,108 MW expected increase in capacity in the Eighth Five-year Plan, 5000 MW is expected to come from private companies.

One of the premises of this thesis lies in the implicit neglect of power development of rural regions in government policy. Much like other infrastructural industries, the condition of the power sector in rural regions remains considerably behind urban centers. Although, about 84% of Indian villages have been electrified, the quality of power is poor, villages fall victim to load shedding, losses are significantly higher due to spread out, low voltage distribution networks and operational and administrative inefficiencies prevent revenue recovery and cost management in these areas. Most of these problems occur in the secondary distribution system. Because of poor monitoring facilities at this level, statistical information on load, power quality and energy use have by and large been estimated, usually conservatively, in official publications. Information access at this level is not easy, making accurate analysis difficult.

Nationally, T & D losses average to around 22%, ranging from 15% in urban areas to over 43% in Kashmir[6]. Losses in the secondary distribution network dominate this percentage. In rural areas, power monitoring facilities are limited, and therefore government publications quoting T&D losses often incorporate conservative estimates of distribution losses.

2.1.4 Institutional and Administrative Framework

The responsibility for electricity under the Indian constitution is shared between the center and the states. The Central Electricity Authority (CEA) is the chief regulatory body that oversees power planning at a national level and is responsible for developing policy in relation to the control and utilization of national power resources. It also conducts and approves technical and economic appraisals of power projects and stipulates guidelines for them.

The National Thermal Power Corporation (NTPC) is the only centralized body partially responsible for generation. Most of the generation and all distribution falls under the

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[6]Eighth Power Plan Program 92-93 to 96-97, Dept. of Power, Government of India, 1991 Annexure 25

responsibility of the State Electricity Boards (SEBs). A small fraction of generation also comes from private and state-owned generating companies. Finally, some private licensees also operate in the area of distribution and generation.

The SEBs set tariffs based on a three percent return on their net fixed assets over and above the recovery of investment in T & D and generation. Most of the SEBs have consistently failed to achieve this rate of return, and this has hampered their ability to invest in new power projects.[7] The financial performance of SEBs is particularly poor in states with a large agricultural base. This is because state governments subsidize agriculture considerably. Furthermore, energy consumption is not metered at the secondary distribution level in several areas, and farmers are charged a flat monthly fee per kW rating of their appliances. Theft, low power quality and technical losses compound the problem of revenue generation.

2.2 Renewables in India

The nature and scale of application of renewable energy technologies in developing countries differ significantly from industrialized nations. In industrialized nations, they have been used primarily as commercialized, grid-connected applications, where the cost of conversion technologies have reduced enough to permit limited penetration of them into the grid. In India, however, renewables have been promoted because of their immense potential for deployment on a small-scale in rural areas primarily for non-electric forms of energy, and, to a lesser extent, for electricity in remote regions where connection to the grid would be too expensive.

Until the late 80s and the 90s, the development of renewable technologies in India depended exclusively on government funding, and therefore on government policy. The Indian government has historically provided more support for renewables than most other developing countries in proportion comparable to several developed countries. The establishment of a Ministry for Non-

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[7]TERI, "Policy to encourage private investment in the Indian power sector - a perspective", TERI Information Digest on Energy, Pg. 97

conventional Energy Sources (MNES) is indicative of the national priority given to renewables. From 1980-81 to 1988-89, investment in renewables increased by a factor of 30[8]. Up to half of this investment went towards a biogas program, with solar photovoltaic and thermal, wind and the cooking stove program receiving comparable amounts. Barring grid-connected wind turbines and solar cookers, most technologies have not matured enough to reach the commercialization stage, and therefore depend heavily on government subsidies.

Until a few years ago, India has had practically no experience with grid-connected PVs. The state of Uttar Pradesh undertook two 100 kW demonstration plants of grid-interactive PV, of which only 25 kW have been actually connected to the grid as of 1994. Investment in PVs have been in stand-alone street lighting, solar lanterns, communication systems and some applications of PV pumps. PVs have always been prohibitively expensive, and it is only for very remote regions and very small-scale applications that they have proved cost-effective. India does have an indigenous solar cell market of 2 MW per annum, which manufactures solar cells at a cost almost three times that of present day cell technology in the US. [9]

With the introduction of economic incentives for private and foreign investment, a completely new face to the deployment of renewables has emerged. Government support has shifted from subsidies and direct funding to fiscal incentives. Specific emphasis has been given to wind energy, because of its demonstrated cost-effectiveness world-wide. Some of the incentives include soft loans from IREDA[10], tax exemptions for five years, and 100% accelerated depreciation. The government planned for 500 MW of private investment in wind in the Eighth Five-year plan, but expect to easily exceed that target by 1995-96, based on proposals received by the government so far.[11] Of the 115 MW installed in 1993-94, over 85% have involved collaborations with foreign wind turbine manufacturers. Clearly, opening up the market to foreign participation has facilitated the growth of a megawatt market for grid-connected renewables like never before. Competition has also brought with it more stringent standards of cost-effectiveness for technologies to compete in this market. Grid-connected PVs will therefore

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[8] Sinha C.S, "Renewable energy programs in India",Pg. 305

[9]Rs. 300 per watt (US$=Rs 31), estimates from Renewable Energy Technology Area. Tata Energy Research Institute, New Delhi

[10]Indian Renewable Energy Development Agency, the financial arm of MNES

[11]Times of India, Bombay, 12 May 1995, Pg. 10

have to seek cost-effective solutions that can attract private investors. For India, this essentially means foreign manufacturers, given the fact that cell manufacturing technology abroad is far more mature and, as mentioned before, one third the cost of indigenous cell production.

2.3 Megawatt Potential for Grid-connected PVs

The purpose of this section is to assess the scope for grid-connected PVs on a nationwide basis. That is, are the characteristics exhibited by Sonepat so unique that on a macro scale they offer only a limited application of grid-connected PVs? Can one qualitatively ascribe a megawatt amount to the scale of their application?

2.3.1 Location Selection Criteria

This thesis focuses on rural demand growth that occurs on, or reasonably close to, the grid in electrified regions such that they require minimal line extensions. This qualification is necessary to distinguish this study from those that compare the cost of installing stand alone PV systems to power a village or region against the cost of extending distribution feeders to these unelectrified areas.

Certain geographic and demographic characteristics of regions can be identified that would potentially make grid-connected PVs attractive. The degree to these characteristics exist will qualitatively influence the attractiveness of PVs, rather than strictly preclude or justify the application of PVs. Such an enumeration provides a useful methodology to intuitively select areas for further analysis into the selection of suitable locations for application[12]. Clearly these criteria can be divided into those that contribute to high costs of conventional electricity on the grid, and those that permit the most cost-effective deployment of solar-powered, intermittent PV systems.

The following list of characteristics of a load center typify regions with high costs of delivery of conventional, centralized power .

• Predominantly agricultural regions, which tend to have:

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[12]The political and social ramifications that affect the choice of solution are discussed in Chapter 5 - this only provides an economic and geographic context for analysis

- high inductive loads that lower power factor, and therefore increase losses. Most common examples include irrigation pumps and tubewells;
- lengthy, low voltage distribution networks that also proportionately increase losses;
- erratic, spiky load curves that harm the efficiency and lifetime of distribution transformers. This increases the cost of maintaining and upgrading transformers.

• Regions located close to urban centers, and therefore fall victim to load shedding and have limited and unreliable power. In such regions, increased capacity tends to be absorbed by the urban centers.

• Regions with significant demand deficits or increasing peak demand. Supply can be met on an incremental basis, on a commensurate scale with demand, taking advantage of the modularity of PV systems and the linear nature of their installation costs.

The following characteristics lend themselves to the most effective deployment of PV power systems.

• Regions with high solar insolation year round, which do not have the same energy potential from wind or small-hydro sources.[13] The year-round insolation will determine the largest capacity that can be installed while ensuring maximum utilization of the system.

• Regions whose peak demands coincide with periods of high solar insolation (which often tends to occur in irrigated agricultural areas). This also contributes to maximizing system utilization, thereby reducing kWh costs of operation. This, and the preceding criterion, are important because grid-connected PVs exclude any storage devices[14], and therefore depends on maximum utilization of the PV system.

2.3.2 Nationwide Scale of Application

Figure 2-1 below illustrates the projected proportion of electricity generation sold for agriculture and irrigation in 1994-95 for select states, which together generate over 85% of the country's

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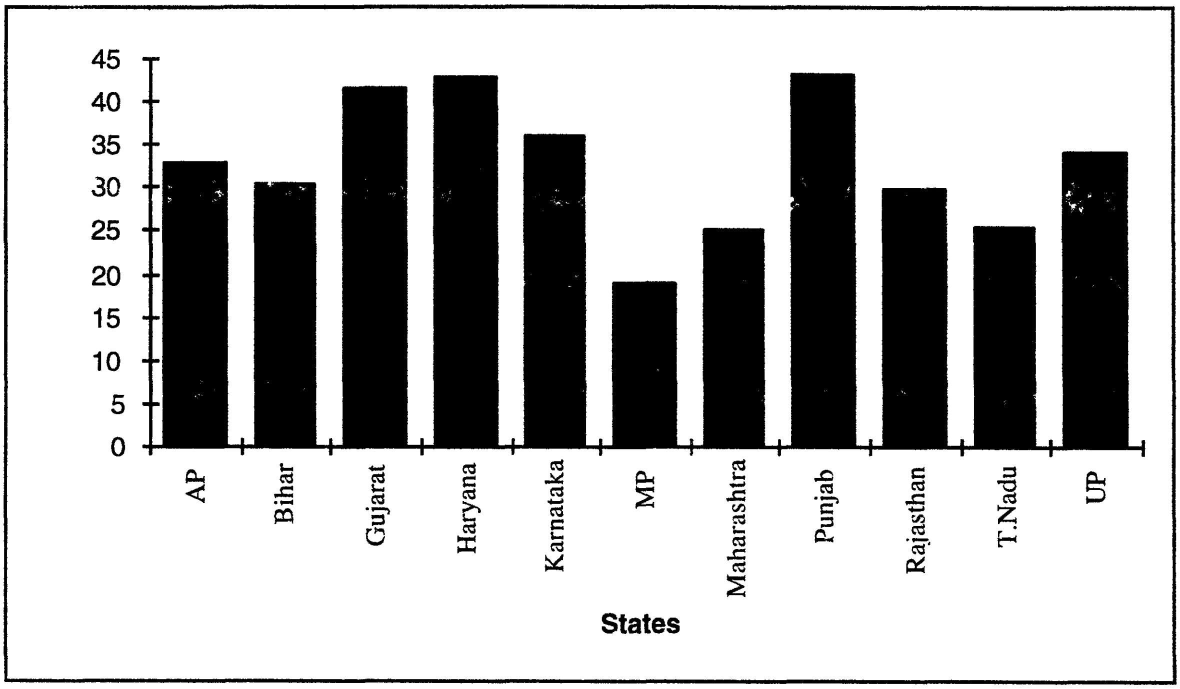
[13]This thesis avoids comparisons with other grid-connected renewable systems, such as wind, assuming that they would be a natural choice when equal potentials exist for their deployment. Thus, regions with solar resource potential at least as high as wind are targeted.

[14]Batteries contribute up to 25% of PV system costs.

power and house over 75% of the country's population. Agriculture consumes more than 20% of total electricity generated in all states, and over 30% in more than half the states[15]. The government projects a deficit of 52,853 MkWh at the end of the Eighth Five-year plan ending in 1996-97, after accounting for current investment plans. Using the percentages from Figure 1 and projected deficits in the respective states, this amounts to a deficit of 15,938 MkWh for agriculture alone in these states.[16]

Figure 2-1: State-wise Consumption of Power from Agriculture/Irrigation (94-95)



Roughly, this corresponds to a capacity upwards of 1,226 MW of grid-connected PV for agriculture in just the next two years[17] - this does not even include any displacement of planned thermal generation.

T & D losses, which this thesis will show are underestimated in government publications, are consistently above 18% for all these states[18]. Statistics on the quality of the distribution systems of individual states was unavailable, but in all likelihood distribution systems in other states are

[15]It is noteworthy that this percentage has gone down since 1992-93, but is expected to decrease only marginally over the next few years.

[16] Source of projected deficits: See Footnote 6, Annexure 35

[17]Assuming 1300 kWh.m^{-2} of generation, and 100 w.m^{-2} of capacity

[18] See Footnote 6, Annexure 25

unlikely to have significantly better power quality in comparison to Haryana, since they have comparable T & D losses. Therefore, by quantifying more accurately the losses in a rural region of Haryana, it would not be illogical to qualitatively extrapolate from the results the existence of a similar discrepancy in losses in rural distribution systems of other states.

2.3.3 Solar Resource Potential across India

Radiation emitted by the sun arrives at the earth in two forms; direct and diffused radiation. Direct solar radiation refers to the quantity of solar radiation falling on a unit area of the earth surface normal to it. Direct radiation depends mainly on latitude, altitude and the season, which determines the distance of the earth from the sun and the amount of sunshine received. Diffused radiation refers to that portion of radiation that arrives at the earth's surface after scattering in the atmosphere, and reflecting diffusely off clouds. Since India lies close to the equator, it has a high level of direct radiation with relatively small seasonal variations. Diffused radiation, however, has a much larger gradient due to the effect of drastically different levels of cloudiness caused by monsoons. Diffused radiation attains its maximum during the monsoons, with a low during winter, while direct radiation is highest in the cloudless months of January and April, with a low in the monsoon months of June and July. Variations on a daily basis occur primarily from the passage of clouds over the sun. The difference in radiation resulting from cloud passage is the difference between the level of total and diffused radiation. Therefore, one can use this property to approximate the variation in solar irradiance to random step changes in irradiance, from the diffused irradiance to the total irradiance. [19]

In all the states chosen above, global (diffused+direct) annual radiation averages over 1800 kWh.m^{-2} per year, with the annual radiation in Haryana at 2020 kWh.m^{-2} per year. (See Figure 2-2). Global radiation varies from 119 kWh.m^{-2} in December to a high of 225.9 in May in the region of Delhi. In June, Delhi receives 196.3 kWh.m^{-2} of global radiation. The diffused component of this ranges from 34.6 kWh.m^{-2} (29%) to 90 kWh.m^{-2} (40%) in May, and 106.2 kWh.m^{-2} (54%) in June. Clearly, even the monsoon months are favorable for the use of PVs, since total irradiance are close the annual highest, and the lowest level in daily variations are the highest in the year.

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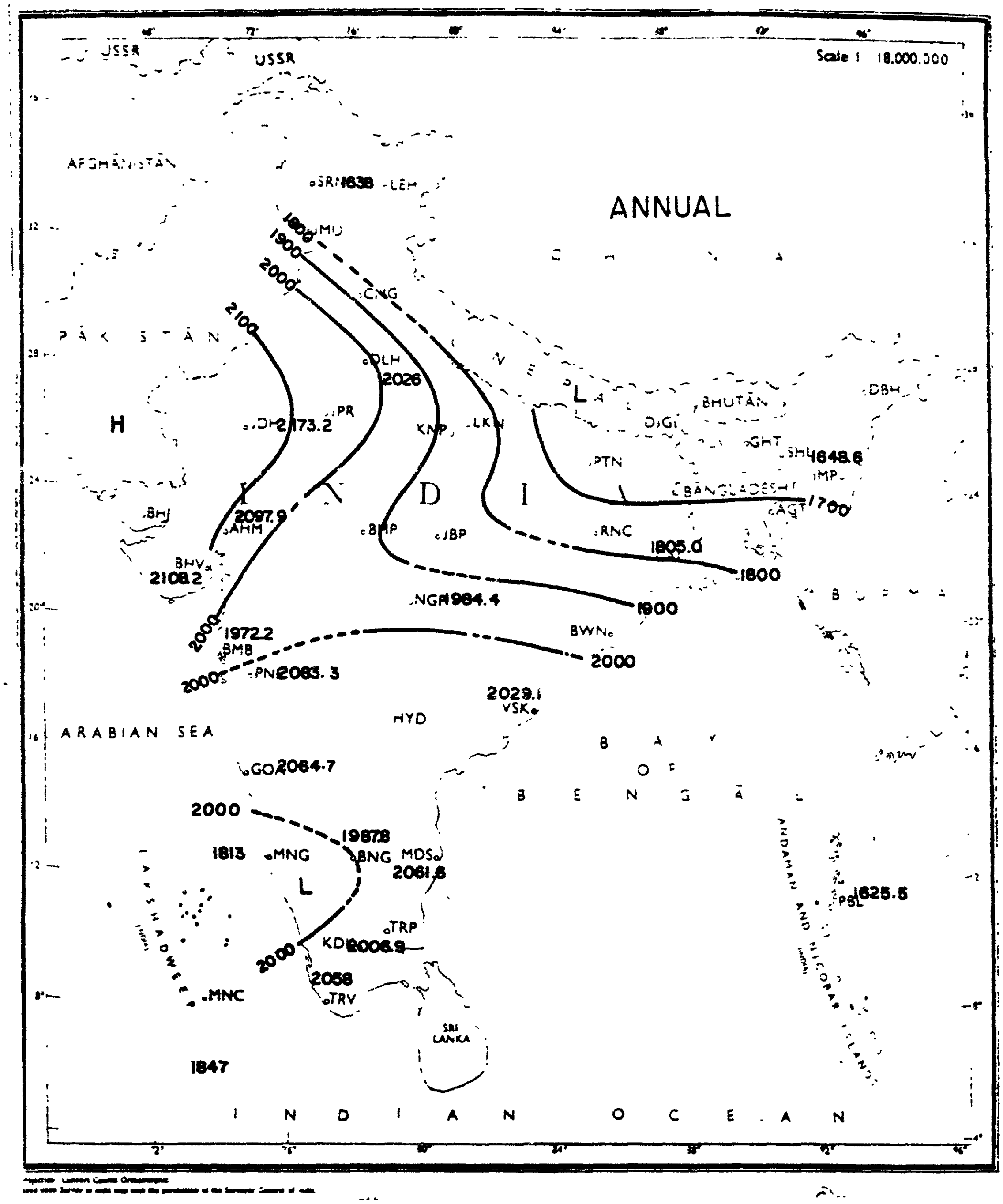
[19]EPRI, "Photovoltaic Generation Effects on Distribution Feeders", Pg. 2-5

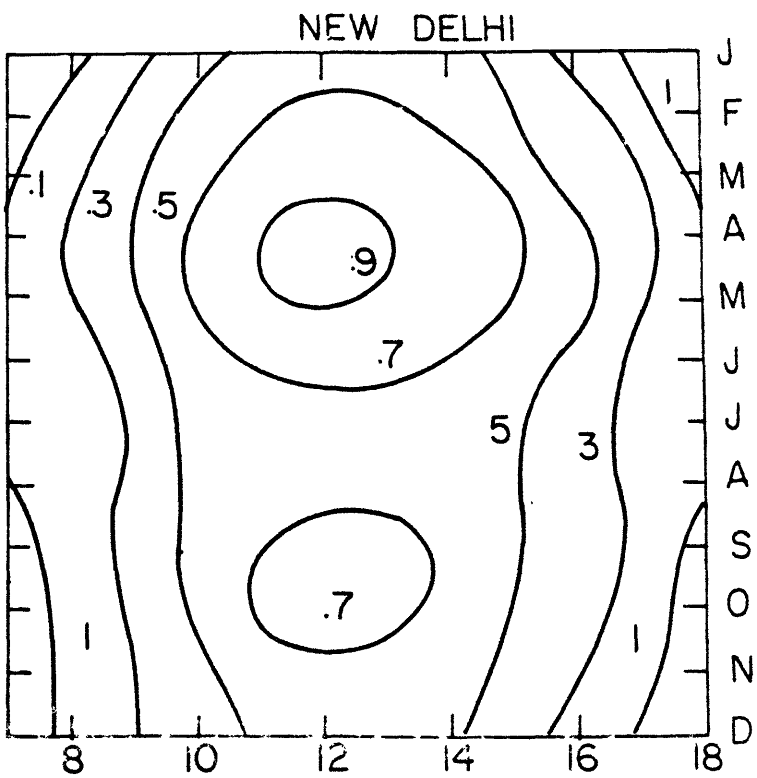
Figure 2-2: Distribution of global solar radiation - (Annual $kWh.m^{-2}.year^{-1}$)



The other states, which cover central, western, and most of South India, in comparison have average annual irradiance levels that are about the same as in Delhi, if not higher. In the western regions of Gujarat and northern Maharashtra, levels are consistently higher. In central India, levels vary both ways to a small degree. Further south, patterns are reversed, with total radiation being higher in winter (140-155 kWh.m^{-2}) and lower in the summer months of May and June (158-200 kWh.m^{-2}). One can therefore safely claim that regional variations in solar radiation will not impact the extrapolation of the results of this study to most of India.

Daily variations in radiation do not differ significantly geographically. Figure 2-3 shows that between 11 a.m. and 2 p.m. levels of global radiation are highest all year round in New Delhi. The number of hours of sunshine Delhi receives averages to 8.2 hours per day, which is also fairly typical of India. [20]

Figure 2-3: Isopleths of hourly totals of global solar radiation - New Delhi (kWh.m^{-2}month^{-1})



[20]Handbook of Solar Radiation Data for India, Pg. 23

2.4 The Case of Sonepat, Haryana

Sonepat, Haryana is a fairly typical, inland agricultural village in the Northern state of Haryana about 40 miles west of New Delhi. Sonepat exhibits all the characteristics described in Section 2.2. Growth patterns in Haryana are also fairly typical - although it is a predominantly agricultural state, the electricity demand growth in the industrial and the commercial sector have been increasing in proportion, while agriculture's share has gradually decreased to around 42%. Paddy and wheat constitute the primary crops grown in Haryana. Over 63% of agricultural demand comes from irrigation tubewells, while the rest includes domestic (household) connections and commercial demand in nearby towns.

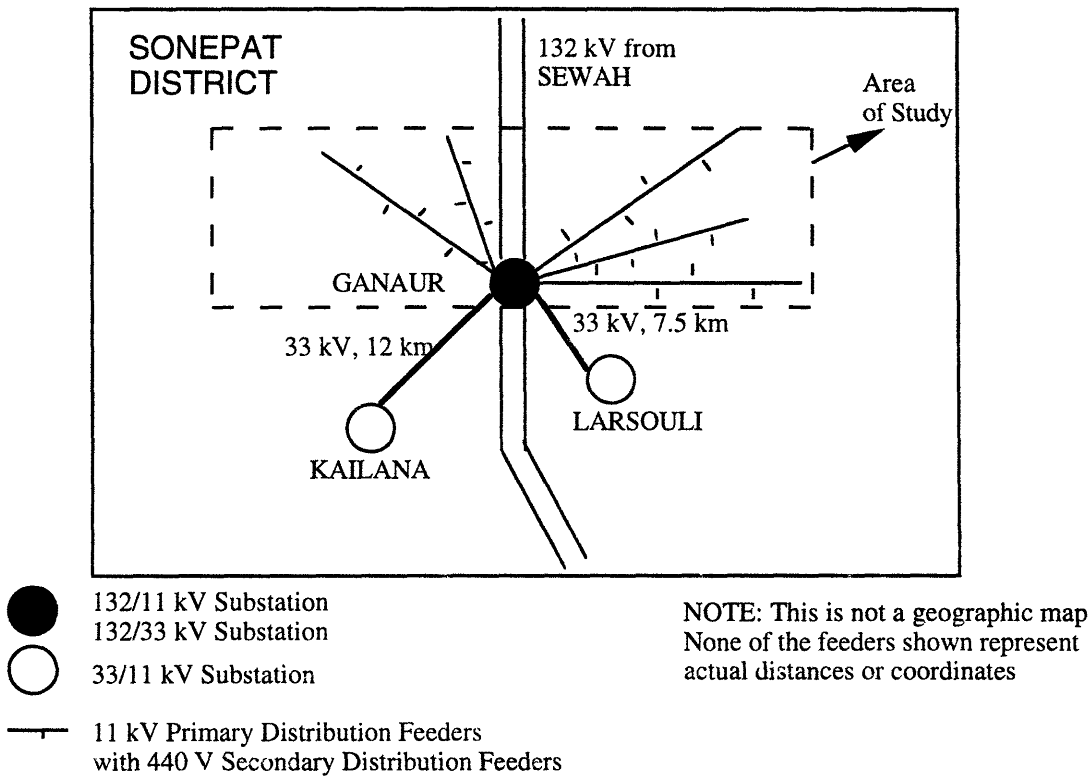
Power quality is very low in Sonepat. The power factor was quoted by the Chief Engineer of the sub-division as being as low as .65-.7. In addition to limited availability of power, described in the next section, erratic power failures are common, most likely due to load-shedding during periods of peak load in the neighboring town of Panipat.

2.4.1 Distribution System

Figure 4 describes the primary distribution system (11 kV) that feeds Sonepat. The focus of this study has been narrowed further to the Samarbandh sub-division of Sonepat, shown in the dotted area, because of limited data availability for the second sub-division.

The details of the primary distribution system have been displayed above to illustrate power availability in Sonepat. Only one feeder, which provides power along a major highway, receives continuous power. The other four feeders alternate in pairs for a period of eight hours, staggered over the course of the day. The first observation relevant here is that of the times of day the feeders are active. The fact the period of availability spans the hours of daylight, from 7 a.m. to 7 p.m. clearly reflect the nature of demand serviced by these feeders - irrigation tubewells. The overlap occurs from 11 a.m. to 3 p.m., which indicates most likely the period of maximum demand. This corresponds directly with periods of maximum solar insolation, as described in the previous section (1.2c). Further details of load and the secondary distribution system obtained for the study will be discussed in more detail in Chapter 2 along with demand analysis and the calculation of losses.

Figure 2-4: Grid Layout - Sonepat, Haryana



The lengths and names of the six 11 kV feeders shown in the above figure are given in Table 2-1.

Table 2-1: 11 kV Feeder Descriptions - (Samarbandh sub-division, Sonepat)

11 kV Feeder	Length	Availability
Ganaur	20 km	7 a.m.-3 p.m.
G.T. Road	55 km	24 hr.
Gumar	37 km	7 a.m.-3 p.m.
Rajlugdi	24 km	11 a.m.-7 p.m.
Chulkana	21 km	11 a.m.-7 p.m.

2.5 Summary

The purpose of this chapter was to provide a very brief background of the economic, institutional and political environment of energy planning in India, and to introduce the rationale and potential scale of application of this thesis. Only the features of the energy sector in India pertinent to this thesis have been discussed. Their importance will attain relevance as they are referenced and discussed through the course of the analysis.

So far, the poor institutional and technical state of the power sector in rural regions has been underscored. Given the lack of adequate reliable information at the distribution level in rural regions, appropriate energy planning for these areas becomes even more difficult. The current trend of power development resulting directly from the liberalization strategy of the 90s targets urban areas with investments in large, centralized capacity additions. Such investments are inappropriate for rural development, both from an economic and technical standpoint.

This thesis targets semi-rural, electrified regions that have growing agricultural demand. Section 2.2 has qualitatively illustrated the enormous scope of grid-connected PVs. Even if current policy trends favoring large, fossil-based investments continue, the shortfall in supply expected leaves room for a market of over 3 GW every few years for agricultural demand only. The region of Sonepat represents a reasonable microcosm of agricultural regions of India. Levels of solar insolation exceed world averages in most regions of the country that have significant agricultural demand. Power availability in Sonepat corroborates the intuitive conjecture that periods of high demand coincide with periods of high solar insolation in irrigated areas. The true difficulty in planning for demand growth in these regions, given the difficulties associated with data acquisition, lies in the details, specific to each region; accurately estimating demand patterns and growth, correctly calculating the cost of providing energy from alternative sources to these areas, and choosing the best option. The following chapters begin to undertake this analysis.

3. Traditional Least Cost Planning Applied to Rural India

This chapter focuses on analyzing traditional capacity planning methods and their applicability to planning in agricultural regions of India. A new methodology is introduced to evaluate the worth of photovoltaics in this context. The advantageous conditions that favor the deployment of PVs and the unique, economically burdensome characteristics of agricultural areas on utilities have been qualitatively described in previous chapters. This chapter along with the next seek to identify and quantify, to the most accurate extent possible, the benefits of photovoltaics in agricultural regions. This chapter justifies the elements of the new methodology that are developed in the next chapter. Traditional methodologies for project evaluation, capacity expansion planning and the specific economic theory behind the evaluation of intermittent generation are presented first. In light of the differing characteristics of the operation of power systems in India and the uniqueness of the agricultural consumer, the departures from conventional interpretation of economic value that must be made in this analysis are explicated.

3.1 Planning Objectives

As in the evaluation of any kind of project, the objectives define the various parameters that must enter the analysis and finally the decision-making process. The objectives depend on who the project belongs to, and the scope of its implementation. A regulatory agency and an independent private power company would have very different perspectives on an evaluation of the economic prudence of building a photovoltaic powered generation plant or a coal plant. The latter would take into account parameters that the former would not necessarily be interested in, such as environmental issues. Generally speaking, however, one can assert that the objective of any decision-maker evaluating the worth of a power plant is to maximize the net benefits, and simultaneously minimize the associated costs over the lifetime of the plant.

The parameters that enter the benefits and costs differ for different decision makers. For instance, a policy maker might be interested in incorporating the benefits to the consumer of grid electricity vs. diesel generators in order to assess investment in power plants, while a utility would be concerned primarily with the revenues that can be generated. Below is a broad framework for encapsulating benefits and costs under different goals with respect to the provision of electricity, adopted from the notation of Munasinghe (1987).

$$NB = \sum_{1}^{t}(TB - SC - OC)/(1+r)^{t} \qquad (3.1)$$

TB = The total (quantifiable) benefits from the project, which in the case of a utility could just be the sales of electricity, which would be a function of demand and price. For a government agency, this might include the improvements in productivity and national income from the additional electricity usage.

OC = The costs incurred by consumers from outages and poor power quality.

SC = The supply costs of the plant, which could be further broken down into generation, transmission and distribution, respectively:

$$SC = GSC + TSC + DSC \qquad (3.2)$$

In addition, certain unquantifiable benefits an costs associated with either option also enter the planning process. In the case of photovoltaics, benefits include the attractiveness of zero emissions and reduced dependence on fossil fuel. An associated cost that would be difficult to quantify is the large amounts of land area required by solar panels.

For a homogenous product such as electricity, the reliability and price are the only characteristics affecting consumer preferences. All three components of Equation 3.1 depend on reliability. The demand for electricity, which is embedded in TB, also depends on reliability and price. It is important to understand that reliability subsumes capacity provision, since a supply constrained power system manifests in poor power quality. When demand and reliability are considered exogenous variables, optimization of Equation 3.1 reduces to the traditional least cost capacity expansion criterion used by utilities of minimizing costs subject to reliability and demand obligations, which is the perspective of the rest of this chapter[21].

3.1.1 Traditional Least Cost Planning

Until recently, utilities have been vertically integrated industries with a typical investment portfolio including large, centralized, generation plants and centralized decision-making structures. Due to the enormous scale of generation investment, transmission and distribution were considered "overheads", and a small, fixed percentage of capital investment in generation. Methodologies used to aid decision-making were therefore based on several assumptions of system configuration and institutional structure that do not necessarily hold any more. Keeping with the terminology of the above section, in a traditional utility planning context, TB would just be P.Q, for a sale of Q kWh of electricity at price P. The only relevant costs incorporated into planning would be

$$SC = \sum_i GSC_i + TSC_i$$

subject to demand D, reliability R.

where GSC_i is loosely defined as the contribution to cost from each participant generator, and TSC_i is a fixed proportion of the capital component of GSC_i, and distribution costs are often neglected. Utilities usually have an obligation to serve that manifests itself as a constraint on the reliability of service, and has different measures, such as reserve margin and Loss of Load Probability (LOLP).

Two levels of planning, distinguished by their time scales, typify decision-making in utilities; On a day to day basis, utilities optimize the dispatch of plants in their generation mix to meet demand at the least possible cost. Operational issues, such as unit commitment and level of spinning reserves typify planning in the short run. On a longer time scale, utilities plan capacity expansion to meet forecasted demand growth, and are concerned with the costs of production and generation over several years, and thus minimize the discounted sum of annualized capital

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[21] Munasinghe M., "Rural Electrification for Development", Pg. 105

and operational costs over a planning period. Clearly, the capacity expansion and replacement differentiates long run planning from planning of operations and dispatch.

3.1.2 Prices and Capacity Planning

The economic signal that drives planning and capacity expansion is price, and indirectly the expectation of future profits. In fact, the need for simultaneous optimal price planning and optimal capacity expansion is recognized for the maximization of the net social benefits of electricity consumption.[22] The nature of the price signal, which has been regulated almost universally until recently, therefore determines the nature of capacity planning in a utility. An "incorrect" price signal can introduce economic inefficiencies in planning, or leave no economic incentive for capacity expansion - although obligatory requirements may require expansion in any case. For example, in the US, average cost-based pricing allowed utilities to pass high capital costs through to consumers and consequently encouraged capital-intensive, bulk investments in power.

The theoretical valuation of intermittent electricity depends on the regulatory, institutional and rate structure, since they determine how costs are calculated and how profits are determined[23]. Rates are important for the valuation of photovoltaics, since they determine the cost at which an intermittent system would appear attractive for investment. If rates are based on average costs, for example, photovoltaics would appear profitable only if they generate at a cost lower than their average cost, when in fact the marginal cost of the electricity being displaced by photovoltaics may be much higher than average costs. Therefore, if rates do not reflect the marginal value of electricity, no incentive exists for investing in intermittent systems. Often rates reflect the short run marginal cost (SRMC) of electricity, in which case the value of an intermittent system lies only in the avoided marginal energy costs.

The pricing of electricity based on the anticipated costs of future investments in capacity is called Long Run Marginal Cost (LRMC) pricing. The LRMC approach differs from the traditional

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[22] Ibid. Pg 100

[23]See Tabors et al. for a good discussion on economic worth of distributed generation in a regulated utility environment.

approach of pricing to recover sunk costs by reflecting in price the desire for future consumption. Among other important objectives of price, this method allocates resources efficiently by considering the financial requirements and economic value of future resources. Such a pricing mechanism therefore creates incentives for capacity expansion. The valuation of intermittent energy systems within the LRMC framework allows for their consideration as an alternative for capacity expansion.

In the agricultural sector of India, as described in more detail in Section 3.2, prices do not reflect any market dynamics or supply costs, and as a result no economic incentive exists to expand capacity. Capacity planning therefore practically has to be decoupled from pricing. The motivation for capacity planning in such an environment is therefore purely on the supply-side, and is driven by the need to reduce costs, and not to increase revenues. The evaluation of the photovoltaics must be analyzed in this context. Arising from the obligation to serve in a regulated environment, utilities might have to plan capacity expansion regardless of its profitability. Two approaches therefore arise in evaluating alternative choices of generation, based on fixed capacity and planned capacity expansion. Let us look more closely at the two different approaches and the effect of evaluating photovoltaics in each context.

3.1.3 SRMC & Optimal Economic Dispatch

Electric utilities face a time-varying demand, and consequently have a time-varying cost of operation and delivery of power. The dispatch order of a generation mix is determined by the short run marginal cost, or the variable operating cost of the plants in increasing order. Based on the load duration curve (LDC), which indicates the number of hours in a year that different levels of capacity are required to meet demand, plants are dispatched up to their maximum availability in their dispatch order till the level of demand and reliability required (or the area under the LDC) are met. The total annual operating cost to the system can be computed by multiplying the hours of operation of each plant by their variable cost.

With the introduction of an intermittent, the concept of dispatch cannot be used, since the output of intermittents is uncontrollable. However, since their marginal costs are usually far below dispatchables (assumed zero), because of the absent fuel requirements, they are modeled as a reduction in demand faced by the utility. This is done by probabilistically (or deterministically for a static analysis of a particular year) adjusting the load curve for every hour of the year and using the resultant LDC to perform the aforementioned procedure to determine system operating costs. As basic economics would suggest, the value to the utility of each unit of generation of an intermittent source is the avoided cost of generation *of that unit.* Therefore, the difference in calculated operating costs between the two scenarios is the avoided cost of generation, and the energy component of the value of photovoltaics.

Clearly, the cost to the utility of supplying power is maximum during peak hours. Therefore, if a photovoltaic panel generates electricity during peak hours of operation, their operational value would be the marginal cost of the peaking plant supplying power at that time. This indicates that the worth of an intermittent would vary with its level of penetration - the higher the level of penetration, the lower its value on average, since the greater the likelihood of its generation during off-peak hours, when electricity is cheaper to produce.

3.1.4 LRMC and Optimal Capacity Expansion

In order to maximize profits, utilities plan a mix of generators that fall into three categories based roughly on their inversely proportional variable and fixed costs of operation - baseload, which constitute capital-intensive, large-scale plants that operate continuously, barring forced and planned outages, and are relatively inexpensive to operate; intermediate, load-following plants that are designed to track daily variations in load, and fall in between the two extreme categories in terms of their costs and time of operation; finally, peaking plants that operate at a very low annual capacity factor, in order to meet peaks in demand. They are relatively inexpensive to build and can be turned on and off fairly easily, unlike baseload plants, but have a high variable cost due to their limited operation[24].

The cost of meeting an incremental demand with capacity additions is the discounted sum of the annualized capital and operational costs over the lifetime of the plants. The capital cost savings from photovoltaics can be found by evaluating their effective load carrying capability (ELCC), and then finding the least-cost mix of dispatchable capacity that they would displace.[25] Effectively, this is the equivalent capacity that photovoltaics would displace while maintaining reliability at the same level. The difference in costs between the capacity mix for the original

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[24] See Johansson, T. et al.. Pg. 1016, for discussion of algorithm to select a least cost capacity mix
[25]Tabors et. al., Pg. 4189

LDC and the photovoltaic-adjusted LDC is the savings resulting from deploying photovoltaics. An interesting measure of the relative suitability of the conditions to the deployment of photovoltaics can be ascertained by dividing the resulting load carrying capability by the rated installed PV capacity. This gives the effective photovoltaic capacity, which can be considered the capital equivalent of the capacity factor.

The ELCC indirectly depends on the correlation between load and distributed generation, and the portion of the LDC that the generation replaces. This is because reliability, usually taken to be the Loss of Load Probability (LOLP), depends on only a small portion of the year, when the likelihood of demand exceeding supply in highest. This clearly occurs during peak hours, when all available plants have been dispatched. Thus, the primary area of the LDC that is of interest for assessing the ELCC is the top load hours[26]. Although a large enough penetration of distributed generation can merit baseload capacity value, the likelihood is rare, and generation that occurs during peak hours will have greater benefits in the long run.

3.1.5 Transmission and Distribution (T&D) Savings

As mentioned in the above section, T&D modeling did not form a significant part of traditional capacity planning until recently. The interest in distributed generation in the US stems partly from an interesting development in the trend of capital investments in T&D since the late 80s. The total investment in T&D across the power industry in 1989 equaled the investment in generation. In 1991, the investment in T&D was predicted to increase to 80% by 1997, according to some forecasts. (*Electric World's* "Forecast 92" [Nov. 1992])[27]. The avoidance, or deferral, of T&D investments in upgrades and extensions therefore also contributes to the value of distributed photovoltaics, and therefore must be incorporated in planning.

Traditionally, T&D savings were factored in the evaluation of distributed generation in instances where line extensions were required to meet electricity demand in remote regions, and hence favored the installation of stand-alone systems that did not require this capital investment. However, in electrified regions where demand grows, T&D equipment can reach operating constraints and require maintenance and upgrades on a regular basis and may contribute

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[26] Hoff, T., "Maximizing the Benefits Derived From PV Plants: Selecting the Best Plant Design and Plant Location", Pg 90-75

[27] EPRI et al.., Distributed Utility Valuation Project, Pg. v

significantly to total system costs. In particular, distribution systems require larger investments than transmission, because most of the power quality problems occur in the distribution system.[28] Because of the presence of higher variations in demand at a sub-station level, distribution transformers and low voltage distribution feeders tend to require the most frequent maintenance. Thus, T&D investments have to be analyzed in parallel to generation to reflect true costs of providing service from centralized sources. Keeping with this extension, one can begin to talk of the capacity utilization of T&D to point to potentially cost-ineffective areas (and therefore candidates for distributed generation), just as the capacity factor of generation plants reflect the relative difference in their cost per kWh of generation.

The estimation of the required investments in T&D, given projected demand growth, requires a large amount of data and the solution of computationally-intensive algorithms, since the violation of constraints can be detected only by solving optimal load-flow type problems for a region. The quantification of T&D savings is thus difficult and site-specific. However, the use of the concept of capacity utilization of T&D and a qualitative comparison of substation transformer ratings and corresponding peak demand can give an idea of the degree of maintenance and up keep required by the T&D of the area, and hence whether distributed generation would be suitable.

3.1.6 Environmental Benefits

The most important benefit of intermittent generation from renewable sources is the avoidance of emissions that are harmful to the environment, such as carbon dioxide and NOx emissions. Several proponents of renewables attempt to quantify the benefits of avoided emissions in economic analyses. Although there are several different harmful emissions released by fossil-based fuels, carbon dioxide is by far the most controversial and important in the consideration of renewables. It is controversial because significant uncertainty still surrounds the scale of the environmental impacts of global warming, and the urgency of the need for action. The only feasible means of reducing emissions significantly is to phase out the use of carbon-based generation technologies, rather than install abatement equipment (CO_2 scrubbers), which would be uneconomical and impractical for the volume of emissions in question. Consequently, a CO_2 conscious planning approach would necessitate a drastically different investment portfolio, and a more expensive one, the benefits of which would be hard to quantify or justify and therefore

[28] Ibid. Pg xiii

incorporate into an economic analysis. Clearly, being an externality, the environmental benefits of renewable sources of energy can only enter the decision-making process of planners through regulatory requirements.

The extent of the environmental benefits depend on the avoided capacity and/or the source of the energy saved from the deployment of renewables. Emission levels, and the mix of pollutants emitted, differ greatly across different fuel types and generation technologies. For example, low grade coal fired technologies emit almost twice the amount of CO_2 emitted by gas turbines per unit of energy generated. In areas where hydro electric projects constitute a significant component of a capacity mix, the comparison becomes more complicated, since hydro plants have a host of different environmental problems. If new capacity from renewables replace energy generated from existing hydro plants, arguably they would have no environmental benefits. This emphasizes again the importance of de-centralized, location-specific analysis for the siting of distributed, renewable sources.

From a developing country's point of view, the real costs of moving away from a carbon-intensive investment path could drastically impede GDP growth and government spending.[29] The allocation of responsibility between countries for the reduction of greenhouse gases is also a contentious issue. A common opinion in developing countries is that even if the need to reduce future emissions may be enormous, and greater in developing countries than industrialized nations, the financial burden of these reductions must be commensurate with the current level of emission contributions from different countries. Under the Framework for Climate Change Convention (FCCC), developing countries do not yet have any quantified obligations to cap emissions, as the developed countries do. Therefore, the likelihood that regulatory standards from domestic initiatives will introduce caps on CO_2 emissions in India are small. The only way that environmental benefits will influence the investment of PVs in India will be through joint implementation projects under FCCC.

[29] Capping emissions to 80% of 1990 levels by 2010 by shifting to a nuclear/renewable capacity mix, amongst other changes, can result in an 80% reduction in GDP growth by 2030. See Eckaus, R., et.al.

3.2 The Case of Electrified Agricultural Regions of India

A straightforward application of the above methodologies to the situation in agricultural regions, such as Sonepat, can only be hoped for. Several conditions complicate the analysis and require clarification such that either the methodologies described above are adjusted or the results of applying these methodologies are interpreted correctly.

3.2.1 Transmission and Distribution Losses

Since traditional planning methods do not distinguish load centers from each other, no provision exists for the modeling of the loss characteristics of different regions. The main thrust of this thesis that motivates the choice of photovoltaics is the presence of high T&D losses in rural regions, which are reduced with distributed generation (depending on the location and capacity of installed sites, losses can be almost eliminated - See Appendix 5). The need to study the distribution system more closely in planning is even greater in rural regions, since power quality is extremely low. Section 3.7 goes into great detail in analyzing and quantifying these losses. From the point of view of capacity planning, the importance of losses is that they contribute to both the peak demand and total energy consumption. *Hence, losses and load are indistinguishable as far as the bulk supply system is concerned.*[30] Since these losses are a function of the square of the load, they steepen the load duration curve significantly. As shown in Figure 3.5.1, the effective peak demand can be as high as 30% greater than the actual peak demand.

In addition to increasing the demand and peak capacity that has to be planned for - and a consequent increase in energy supply - losses also strain equipment on the distribution system, as will be shown in Section 3.7. The damage to equipment resulting from losses translates to economic losses to the utility only if investments in the upgrade of equipment is a priority of the utility. The detrimental effect of demand losses can therefore be a red herring, depending on the policy perspective that is taken on the issue. As mentioned in Chapter 2, agricultural consumers are considered an economic burden, and they are the first victims of load shedding during system peaks. Since they do not generate significant revenues for the utility, the incentive to upgrade equipment is low. The economic solution therefore is simply to cease provision of service. This

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[30] Munasinghe M , Pg. 147

is in fact apparent in several parts of the country, where power quality is poor, voltages are low, and several villages, although electrified, do not receive any power due to non-functional distribution equipment.

However, political and/or regulatory pressures would not allow a deliberate restriction of service. So long as power flows to rural areas, utility providers incur *energy* costs that are far greater than power generated locally. The problem is that demand losses, although very significant, represent an *externality*, and do not necessarily affect the decision-making criteria of state utilities. An argument to promote photovoltaics to justify the *economic* savings resulting from reduced demand losses cannot be made if the costs of these losses are borne by subsidized consumers in the form of poor power quality, rather than by the utility in the form of higher capital investments. Thus, the perceived advantage of an alternative to centralized power generation manifests itself as an unquantifiable benefit.

3.2.2 Different Load Duration Curves

Significant supply deficits constrain most State Electricity Boards. As a result, rural regions, which are the economically least valuable to utilities, fall victim to load shedding. The utility thus completely avoids supplying power to these regions during peak load. One ramification of this is that a portion of demand occurring during periods of no power is *re-distributed*, while the rest remains in the form of *unmet energy*. Thus, the load duration curve seen by a utility without photovoltaics differs from one with photovoltaics, and has a greater portion of baseload. The degree to which the LDC changes depends on the flexibility of consumer demand patterns, which cannot be predicted a priori.

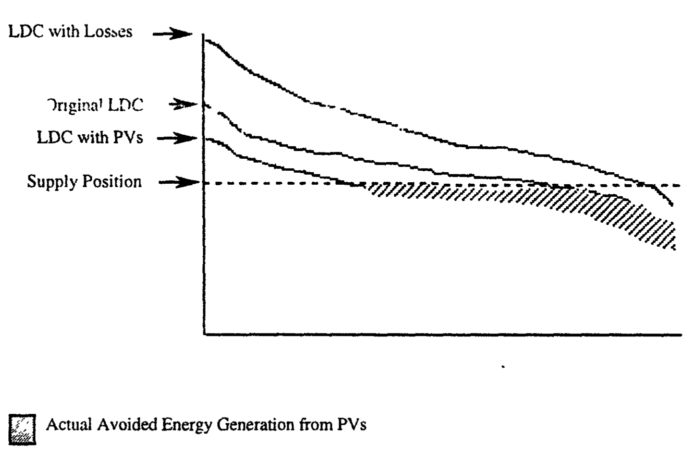
3.2.3 Undervaluation of Photovoltaics with SRMC Planning

If one assumes the present tariff structure for agricultural consumers, the value of photovoltaics can only be considered as a replacement to expensive peak load *within* the present generation mix, and not as an alternative for capacity expansion. A significant re-appraisal of the value of photovoltaics is required because the use of this avoided energy cost would significantly undervalue the worth of photovoltaics for the following reason.

Because of peak shaving, photovoltaics, the deployment of which necessitate the curtailment of load-shedding[31], would largely fulfill unmet demand. Therefore, from a strict utility perspective, only that portion of photovoltaic generation that actually replaces utility generation in the absence of photovoltaics can be counted as avoided energy cost, and not the portion of PV generation that meets demand that was unmet before. (The shaded area in Figure 3-1 under the "supply position"). As is clear from the diagram, besides only accounting for part of the PV output, the avoided energy is that which is produced at the lowest cost by mostly baseload capacity.

On the basis of avoided energy costs, the greater the level of installed capacity, the more attractive a photovoltaic system would be. This result can be recognized as just the corollary of the known fact that photovoltaics are most cost-effective when they replace expensive, peak load. In a supply-constrained system, peak load is not being met anyway, and consequently, no reasonable justification can exist for the deployment of PVs to replace baseload generation.

Figure 3-1: Illustration of Supply Constrained Capacity Planning



3.2.4 Value of Unmet Energy

This interpretation of the value of photovoltaics therefore does not account for benefits that are difficult to quantify as energy savings; primarily, the value of unmet energy. Although this argument does not favor photovoltaic over any other form of generation that would also reduce

[31]For technical reasons, described in Appendix 5

unmet energy, the presence of losses proportional to the square of the peak load significantly increases the reduction in unmet energy and in the peak demand of the system attained by PVs in comparison to centralized sources.

In this particular case, the unmet energy is that of the agricultural consumer. A policy maker might want to quantify the value of this unmet energy to better reflect the value of a photovoltaic system. The most obvious method of valuing unmet energy, from the point of view of the utility, is to ascertain the foregone revenue from this unmet energy. As mentioned in Chapter 1, the agricultural consumer often pays a flat rate per kW rating of their appliances independent of energy consumption, because of the absence of energy meters. Therefore, the *economic benefit to the utility of supplying this additional energy is zero.*

From the perspective of social welfare, the value of the marginal provision of electricity is the value to the consumer of using this additional energy. This can translate to either his willingness to pay for the additional unit, the monetary value of the next best alternative, or, in a more holistic sense, the increase in productivity that can result from the additional energy. However, these do not provide an economically justifiable argument from a utility's perspective.

3.3 Improved Methodology for Capacity Planning in Agricultural India

3.3.1 Assumptions

The analysis of the previous section shows that the provision of improved service in an economically justifiable manner to agricultural consumers is untenable. Currently, the subsidization of agriculture already puts a burden on state electricity boards. To improve the quality of service to agriculture without any financial incentive would be unrealistic. It is a known fact that reform of SEBs, particularly tariff reform, is required to induce financial and economic efficiency such that improvements in the provision of power can be made[32]. Certain assumptions need to be made to proceed with a justifiable analysis of any kind of capacity expansion.

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[32]Ministry of Power, India, "The legal and policy frameworks of private power developments - facts and clarifications", TERI Information Digest on Energy, Pg 122

• The most fundamental assumption is that SEBs operate in a framework of LRMC planning, such that the incentives and preconditions exist for meeting all unmet demand in rural regions through the expansion of capacity. That is, an arbitrary target of demand growth and reliability must be assumed to be the goals of the SEBs, towards which a least cost expansion plan is sought. This implies that photovoltaics will have a capacity value, aside from just energy savings. The evaluation of the worth of photovoltaics then reduces to a comparative analysis of alternative approaches to meeting this target. Such an approach skirts around the problem of facing different demand curves in the presence and absence of load shedding, since the optimal plan would not require load shedding. Both investment paths would face the same demand curve - that being the "natural" curve, representing consumer patterns in the presence of continuous power supply. This assumption also obviates the unusual interpretation of avoided energy costs in a supply-constrained environment described above. Without doubt, the validity of this assumption is extremely important, since the benefits of photovoltaics drastically changes in the absence of it. The discussion of the previous section has already described the implications of withdrawing these assumptions and evaluating photovoltaics in the current power context. Chapter 5 investigates from a policy perspective the likelihood of these assumptions being realistic and commensurate with current policy trends.

• The economic analysis for optimal capacity planning must remain decoupled from the tariff structure. Effectively, this means that demand is considered an inelastic, exogenous input in capacity planning, which in turn requires that tariffs remain flat and close to nothing, as they do today. This is a realistic assumption, because the system is in fact currently severely supply-constrained as a result of the tariff structure, and therefore demand can be assumed to be fixed.[33]

[33] Chapter 5 investigates the necessity of reforming tariffs, and the ramifications of the resulting change in demand on projected growth and capacity planning.

• Finally, this analysis treats a localized region as a microcosm of the planning area. That is, the mix of generation received by this region is assumed to be the same as the energy mix of the entire planning area. This analysis would therefore represent the incremental capacity expansion required by the SEB to meet demand growth in the local region studied. Therefore, the region of impact on the load duration curve facing the SEB of this local region must be ascertained in order to determine the avoided costs, for which a knowledge of the load characteristics of the planning area is required.

3.3.2 Salient Characteristics

Given the institutional, economic and technical differences present in the power systems of rural regions of India, it is essential to use a modified approach to analyze capacity expansion. Based on the standard measures of economic valuation of generation technologies described above and the variations and unique characteristics of the Indian context, a new methodology has been developed to evaluate the economic value to a utility of choosing grid-connected photovoltaics to expanding capacity in rural regions characterized by features described thus far. The most salient aspects of this methodology are listed below:

• Cumulative transmission and distribution losses from the assumed point of generation to the location studied have been calculated and factored into the hourly load to reflect the actual demand facing the utility;

• This methodology emphasizes de-centralized planning in order to more accurately reflect the characteristics of the distribution system in the region;

• The Monte Carlo method modeled analyzes the impact of the random nature of solar insolation, so that a more realistic range of results of the value of photovoltaics is obtained;

• The analysis concentrates on the benefits of distributed photovoltaics, both quantifiable and qualitative, thereby obviating the need to make assumptions about photovoltaic costs. The economic value of photovoltaics is determined by calculating all the relevant avoided costs (capital, energy and T&D) for a certain penetration level of photovoltaics.

4. Model Description and Implementation

So far we have seen a justification for certain modifications to the traditional least cost planning approach, based on a load model described in Section 3.1.3. These modifications comprise chiefly the application of principles of decentralized planning, so that system characteristics specific to a region can be modeled, thereby leading to a more accurate and focused analysis. The two areas that have been modeled in considerable detail are the hourly losses in the distribution system and the load characteristics of a predominantly agricultural community. This chapter walks through the implementation and development of the simulated production cost model based on the methodology qualitatively described in the previous chapter.

The model is illustrated by application to the case study that has been the focus of this thesis - Sonepat, Haryana. In addition to illustrating the methodology presented here, the purpose of this simulation is also to estimate the value of photovoltaics in Sonepat. A methodology is presented and used to calculate distribution losses for Sonepat in detail in order to accurately reflect the cost of conventional electricity. A production cost model of Haryana then calculates the economic impact of a penetration of photovoltaics, taking into account the characteristics of the load and distribution system specific to Sonepat.

4.1 Model Parameters

To summarize, the following parameters have been identified as benefits of distributed PVs:

Quantified in Model

- Avoided capital costs of photovoltaics as an option of capacity expansion;
- Avoided energy costs;
- Avoided T&D losses - both energy losses and the avoided generation capacity required to meet demand losses;

Qualitative

- Avoided investment in distribution equipment;
- Environmental benefits of avoided emissions.

Parameters Varied for Sensitivity Analysis:

Power Factor

.7	Estimation of Status Quo
.85	A reasonable target for improvement
.95	A Best Case Scenario

Avoided Capacity Generation Cost

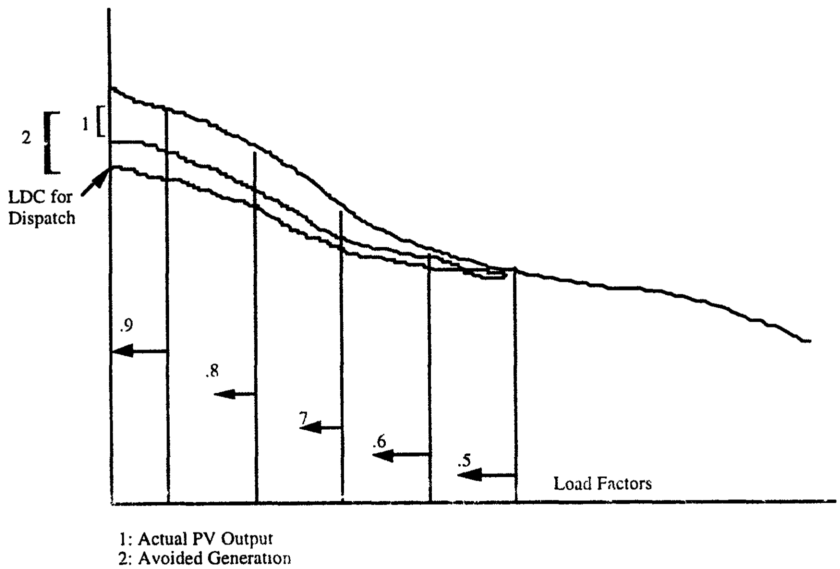
$750/kW	Reasonable Estimation for a Peaker
$1000/kW	Proposed in Current Projects in India
$1250/kW	Baseload Plant (See Section 4.8.4)

4.2 Load Adjustment for Intermittent (with Losses)

The incorporation of losses into the analysis follows from an interpretation similar to that of non-dispatchable generation. As described in Section 3.2.3, since the marginal costs of non-dispatchable generation are close to zero, their output can be treated as a demand adjustment. So long as their hourly output is subtracted (or convolved, in the probabilistic case) from the system load prior to creating a LDC for dispatchables, such an assumption is accurate. Similarly, earlier it was shown that losses are identical to unmetered loads, since they add an energy and demand component to the system load curve just like any other load. They differ in that they are predictable, and dependent on other loads. Given certain simplifying assumptions of distribution feeder configuration, they can be considered, from a planning perspective, a point source of demand. Just like non-dispatchables, however, they are time-varying, since load is time-varying, and an accurate representation of them must reflect this.

Converse to intermittent generation, losses are added ex ante to the load duration curve based on varying load factors. Rather than calculate hourly loss factors, which would attempt to produce a degree of accuracy in the analysis greater than that present in the estimation of loads, different losses were calculated for ranges of load factors. From the point of view of facing losses, two types of generation were distinguished; centralized, point-source generation that would incur all the losses incorporated in the analysis, and distributed on-site photovoltaics, which would not incur these losses[34]. Hence, for every kWh of PV output, (1+ L/100) kWh are subtracted from the LDC, where L is the loss factor for the range of load factors within which the load factor of that hour falls.

Figure 4-1: Illustration of Load Adjustment for Intermittent with Losses



It is clear that the calculation of losses and the estimation of the load are key components to this analysis. The following two sections present methodologies for load estimation in rural India, and loss calculation for a rural distribution system with limited data.

[34] The validity/accuracy of this assumption has very important implications for the siting of PVs. See Appendix 5 for a discussion and analysis of this issue

4.3 Load analysis

An efficient utilization of an intermittent source of energy depends on the degree of coincidence of power generation with load patterns. For the purposes of ascertaining the suitability of an intermittent resource, daily load variations are therefore important. Analysis of intermittent systems in regions with poor data availability is very difficult. Rural areas in India tend to be a low priority of power planners, and records of load variations in agricultural areas are inaccurate, and sometimes even spurious.[35] Very often, projections of peak demand lump in estimates of theft and unaccounted T&D losses, since they are both indistinguishable from revenue-generating demand. Since the economic analysis assumes the objective of meeting all demand, the estimation of only that portion of demand that generates revenues was not of concern. An estimate for the peak demand from a local official was therefore used for this analysis. More importantly, the daily and annual variations merited further analysis in order to track the performance of an intermittent system accurately. Additionally, a more accurate load curve permits an analysis of the capacity of photovoltaics that can be installed in a region such that they operate at a maximal capacity utilization.

This section presents a simple, practical methodology for estimating an annual load curve for agricultural demand, with an illustration for the particular case of Sonepat, Haryana. Based for the most part on climatological data, knowledge of crop water requirements and irrigation patterns characteristic of the region, and partially from conversations with local officials of the Haryana State Electricity Board, a reasonable approximation to the annual load curve is derived. As mentioned in Chapter 2, the choice of the times of operation of the primary distribution feeders in Sonepat offer hints for possible periods of peak demand. Load data was approximated at an hourly rate, which was the degree of granularity of the solar insolation data. This method permits a qualitative comparison of agricultural demand with solar insolation. Since all the data used were averages of measurements made over several years, the resulting load duration curve is fairly representative of demand patterns. It should also be emphasized once again that the load

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[35] It should be mentioned that the level of accuracy of load representation attempted here exceeds the level of detail that could have been reliably obtained from local offices of the State Electricity Board for rural areas. From fieldwork conducted, it was learned that the log books containing hourly recordings of load at the substation level appeared inconsistent - apparently, most knowledge of the area is acquired from experience, and seldom recorded correctly.

distribution being estimated represents "natural" demand patterns that would be seen with continuous power supply, and not one that reflects demand in a supply-constrained environment where electricity demand shifts to accommodate load shedding.

4.3.1 Methodology

In order to determine the annual load curve, two normalized representations, for daily variations and for monthly variations, were developed. The demand at any hour in the year was obtained by the product of the peak demand, the normalized index of the hour of the day, and the normalized index for the month it belonged to. For domestic and industrial demand, monthly variations were ignored, and daily variations were obtained from load characteristics of Maharashtra. The primary application of this methodology was to agriculture. The two dimensions of day and month were created chiefly to incorporate the social patterns of daily energy use and the effect of the monsoon on annual irrigation patterns.

Monthly Variations - Irrigation Patterns

Haryana is classified as a hot, arid sub-tropical region of India.[36] Its chief crops are rice and wheat, but it also grows several other cash crops, such as maize, sugarcane, and groundnut. It is one of the more successful agricultural states that benefited from the Green Revolution, and therefore has a high percentage of high-yielding varieties of crops, and substantial investments in the mechanization of agriculture and irrigation. The resulting intensity of land use and the shortened life-cycle of crops make Haryana a very productive agricultural environment with high irrigation needs.

Topographically, Haryana consists mainly of lowland plains that have substantial quantities of shallow groundwater, and is not drained significantly by the Gangetic river system. Electric pumps in tubewells therefore constitute the primary form of irrigation. Since the monsoon in this region is very erratic, prone to drought and not very strong, most of the paddy fields also depend on irrigation, rather than the rains for their development.

[36] Tata Energy Data Directory & Yearbook, Pg. 172

The water requirements for crops depend on the type of crop, the type of soil, evaporation rates, and other climatic factors. It has been observed in India, that for any agro-climatic zone, the water requirements during an entire cropping season vary very little for crops other than rice.[37] The approximate water requirements for different cropping seasons are shown in the table below (also for crops other than rice).

Table 4-1: Water Requirements for crops other than rice (mm/ha)

Kharif (Jul-Oct)	Rabi (Nov-Mar)	Summer (Mar-Jun)
5000-6000	4000-5000	8000-9000

For rice, the typical season for lowland plains starts in June with the coming of the monsoons and carries on to the end of the year. The water requirements are 5400 mm per hectare per month. [38] Under the assumption that 25% of irrigated area in Haryana holds rice, the total irrigation requirements per month were estimated, adjusted for the mean rainfall per month[39], and finally normalized to obtain the monthly variation in agricultural demand shown below in Figure 4-2. The unpredictability of the monsoons and the high dependence of cropping patterns on the monsoons make accurate estimation of irrigation demand very difficult. Attempts to analytically reflect the variable nature of rainfall as a stochastic input on the one hand, or by choosing bounds to study sensitivity on the other, would be either too cumbersome or arbitrary, and not add value to the analysis. The use of an average over a thirty year period was assumed to be sufficient.

Figure 4-2 displays the correlation between solar insolation and irrigation demand. The natural tendency for solar insolation and irrigation demand to decrease during the peak of the monsoon favors the use of photovoltaics. The erratic onset of the monsoon would be accompanied by a corresponding shift in the trough of solar insolation. The data above shows averages over thirty years for both insolation and monsoon, and hence is a good indication of their correlation.

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[37] Ibid. Pg 163

[38] Barker et al., "The Rice Economy of Asia", Pg. 24

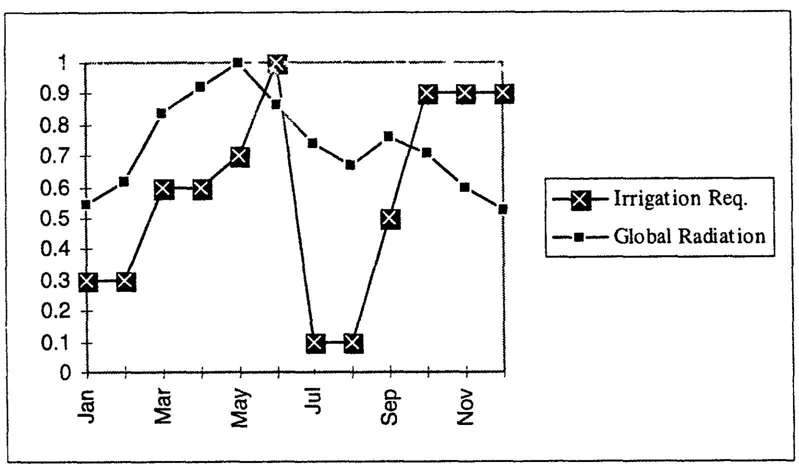
[39] National Climatic Data Center, "Monthly Climate Data For The World", Jan-Dec 1994

Table 4-2: Estimation of Irrigation Requirements for Haryana

Month	Rainfall (mm/month)	Rice Req. (mm/ha.month)	Other Crop Req. (mm/ha.month)	Net Normalized Irrigation Req.
Jan.	200	1125	0	0.27
Feb.	150	1125	0	0.29
Mar.	160	2125	0	0.60
Apr.	70	2125	0	0.64
May.	0	2125	0	0.67
Jun.	570	2125	5400	1.00
Jul.	2350	1375	5400	0.10
Aug.	2480	1375	5400	0.10
Sep.	1260	1375	5400	0.47
Oct.	350	1375	5400	0.86
Nov.	120	1125	5400	0.87
Dec.	80	1125	5400	0.89

Source: See Footnote 36, 37

Figure 4-2: Normalized Variations In Irrigation Requirements And Solar Radiation



Daily Variations

It was assumed that irrigation only occurred during the day, and that night time load corresponded to domestic energy demand. Since hardly any industry exists in this region, the variability of demand over a day is significant.

Figure 4-3: Normalized Daily Load Variations

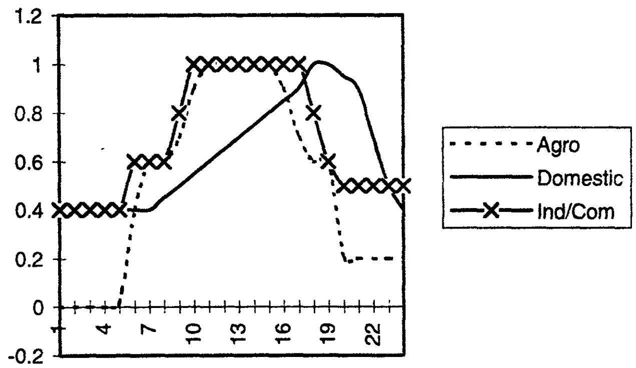
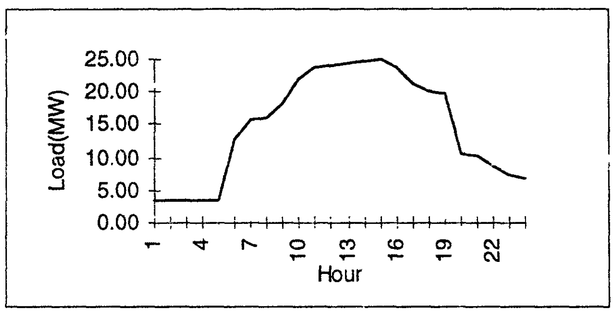


Figure 4-4: Cumulative Daily Load Curve - Sonepat, Haryana



Using the above methodology and the data below, load duration curves for Sonepat and Haryana were derived. The figures for Haryana in Table 3.6.2 represent the predicted load forecast for Haryana in 1996-97.

Table 4-3: Sectoral Breakdown of Demand, Sonepat

Sector	Demand (%)
Agriculture	63
Industry	8
Commercial	0
Domestic	29
Total (MW)	23
Total Energy (MWh)	100,200

Table 4-4: Sectoral Breakdown of Demand, Haryana

Sector	Demand (%)
Agriculture	43
Industry	29
Commercial	3.5
Domestic	16.5
Total (MW)	3050
Total Energy (MWh)	15,180,000

The agricultural nature of Sonepat can be seen in the sectoral distribution of demand for electricity. Irrigation and lighting essentially constitute the bulk of demand. The remaining sectors were omitted from the analysis for simplicity, due to their minimal contribution. The total energy figure was derived from an average annual load factor of .6, suggested by the Chief Engineer of Sonepat District.[40] One can also notice that Haryana as a whole has a larger percentage of industry and a lower proportion of agriculture than Sonepat. Given the highly typical nature of Sonepat, one can reasonably conclude that the 40% of agricultural demand seen in Haryana could very well exhibit characteristics seen in Sonepat. This motivates the justification for apportioning to the section of the demand growth representing agricultural loads a far higher level of demand than the peak of 23 MW seen in Sonepat. It also hints at the hypothesis that load growth in agricultural regions falls in the peak and intermediate regions of Haryana's LDC, a fact that is corroborated by the resulting LDC below.

The resulting load duration curves of both Sonepat and Haryana as a whole (Figure 4-6, 4-7) do not fit the shape of load curves typically seen by utilities with less agricultural demand. There are several reasons for this. First, Sonepat represents a small region with a particular load characteristic and a high coincidence factor, as opposed to larger systems that see less variability in total demand over time due to greater heterogeneity in demand. The dominance of agricultural demand in this load profile also contributes to its steepness primarily because of its concentration during the day. The last section of the load curve with a flat, low demand represents mainly night-time demand. Because of the absence of any industry in this region, this constitutes barely

[40] Interview conducted on July 20, 1994 with Chief Engineer, Haryana State Electricity Board, Sonepat District

Figure 4-5: Annual Load Characteristics - Haryana 1996-7

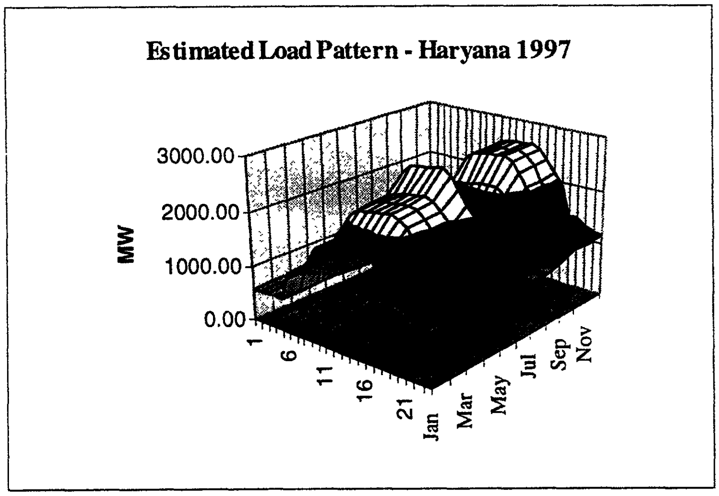


Figure 4-6: LDC, Agricultural Regions in Haryana (based on Sonepat) 1996-7

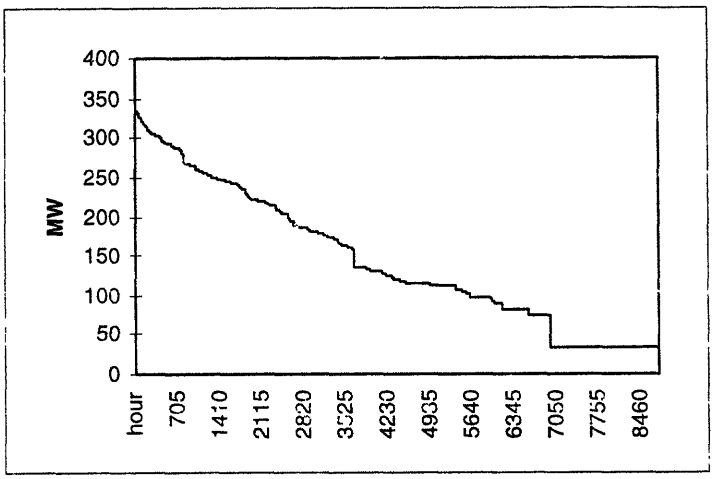
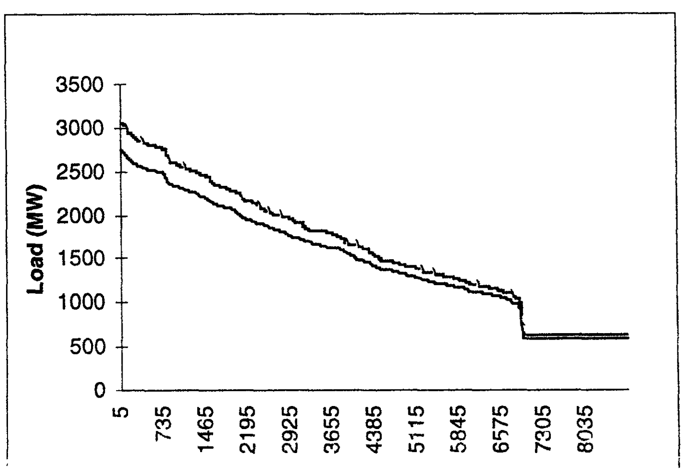


Figure 4-7: LDC, Haryana + Agricultural Growth 1996-7



15% of peak demand. The incorporation of losses as an additional load exacerbates the unique steepness of this curve, because they increase with the square of the load.

The implications for the planning of capacity expansion is that this region contributes to a larger extent to the intermediate and peak portions of the utility load curve (in this case Haryana). This can be seen in Figure 4-7, where hourly loads of agricultural growth and Haryana were added before the construction of a joint LDC. Two very important inferences can be drawn from this result:

- *Baseload expansion would not be economical for utilities serving regions dominated by regions exhibiting the characteristics of Sonepat - namely non-industrial, agricultural, semi-rural regions;*

- *Regions such as these have the highest capacity to absorb photovoltaics due to the concentration of demand during the day.*

4.4 Load-related losses

The purpose of this section is to quantify the load-related losses in the distribution system in Sonepat, Haryana. As mentioned earlier, agricultural regions with large distribution networks and a high percentage of inductive loads have a very poor power factor and high real and reactive power losses, which significantly increase the cost of supplying electricity to these areas. Since most rural regions are not monitored, and load patterns are not known by state authorities, no accurate estimate of losses currently exist.

4.4.1 Characteristics of Distribution Losses

Load-related losses differ from magnetic losses, which occur in transformers and other regulating equipment, in that they vary with the level of load the power system serves. Distribution feeders suffer load-related losses for the following reasons:

1) line losses in the conductors, which vary with the square of the current (I^2R) and

in proportion to the length of feeders;

2) reactive line losses, which are caused by inductive loads in the system (e.g. electric pumps for tubewells) and reduce the power available to do useful work;
3) distribution transformer core and leakage losses (real and reactive);
4) losses due to imbalance in the three phases;
5) *losses due to power theft, or the unaccounted for energy that does not generate revenues for the State Electricity Board.*

The line losses are influenced by two essential characteristics of the load they serve; the load factor and the power factor. The former determines the level of current flowing at any time. The power factor increases the reactive component of current and therefore compounds line losses. However, it improves transformer core losses, which depend on absolute voltage magnitude, because the voltage drop decreases with improved power factor. The result is that total losses are inversely proportional to the square root of the power factor.

The reactive losses can be calculated directly from the power factor. They reduce the available real power by a factor of power factor, and hence can be accordingly interpreted as a percentage loss of total power. For example, an inductive electric pump that has a rating of 1 kW and draws power at a lagging power factor of .7 demands 1.43 kVA of power, rather than 1 kVA with a unity power factor. Hence, 30% of power delivered has to be in the form of reactive power.

The losses due to theft have been emphasized because of their uniqueness to the conditions encountered in this study. This is a factor prevalent in most parts of India. In reality, theft of power clearly constitutes a form of suppressed demand. However, from an economic standpoint, they are not part of the system, since they are invisible to the distributor. They do not contribute to their revenues and cannot be monitored.

4.4.2 Economic Consequences of Distribution Losses

It has already been shown earlier that technical losses are equivalent to an increase in demand. Clearly, the wasted energy from losses translates directly to excess production of power that results in an additional annual energy cost. Their presence also increases peak demand, and therefore requires planners to account for additional capacity. These two manifestations can be categorized as energy and demand losses, and result in increased generation costs.

The impact of losses, if they are known, on a utility's dispatch and capacity mix can be accounted for easily by adjusting forecasted demand. Another effect of losses that is much harder to ascertain and isolate is the stress on transmission and distribution equipment, such as distribution transformers. By increasing the load of distribution feeders, losses increase the likelihood of damage to distribution equipment. While agricultural regions already tend to have shortages of power, the presence of losses exacerbates the stress on transformers. Since losses are proportional to the square of the current, during peak load the losses are highest, and therefore most likely to exceed the rated capacity of transformers. Since the damage to equipment is attributable to overloading, and not to losses per se, losses only contribute to increased T&D costs in regions with high loading of feeders. In order to assess these costs, a detailed feeder-by-feeder analysis of a distribution system would be necessary to ascertain whether losses cause overloading to the extent that failure in equipment actually results.

4.4.3 Losses in Agricultural Regions

Agricultural regions that meet their water needs from electrically powered irrigation tend to have very low power factors. This phenomenon is not unexpected, since agricultural regions tend to be expanses of isolated fields that are fed by large irrigation systems. with a small proportion of sources of power consumption other than inductive irrigation pumps. The obvious solution to improving the power factor is to provide a source of reactive power, such as shunt capacitors, at the distribution level. Most power systems are designed to transport only active power from centralized points of generation over long distances to points of distribution where reactive power is supplied locally. This obviates the need to transport reactive power over long distances, which adversely affects voltage levels, and in turn limit the ability of transmission lines to carry active power, and also increase the total carrying capacity requirements on equipment, such as transformers.

The need for reactive power compensation at all voltage levels is quantified and planned for annually by the Northern Regional Electricity Board. As an example, in 1991 total reactive demand in Haryana was 1462 MVAR compared to an active load of 1732 MW. However, evidence suggests that recommendations for reactive compensation typically study transmission lines, and not distribution networks. In a system study carried out by the Northern Regional Electricity Board to determine requirements for shunt capacitors in the Northern Region Grid, reactive compensation for the sub-transmission and distribution system was accounted for as a 10% increase over the estimate for the 220/132 kV level of recommendations.[41] It is questionable whether such an estimation would adequately compensate for reactive losses at a distribution level. The absence of power factor improvement targeted for the rural distribution system reflects once again the economic reality that non-remunerative customers cannot be afforded the luxury of quality improvement.

All distribution feeders in Sonepat are three phase conductors, and therefore suffer higher line losses than single phase feeders. It is very likely that imbalances between phases exist and compound losses, but the inability to take measurements on the feeders precluded an analysis of excess losses due to imbalances. In the regions targeted in this thesis, load factors tend to be fairly high because of the perennial need for irrigation. As mentioned in the previous section, irrigation requirements also do not differ greatly in quantity throughout the year. However, the monsoon rains do reduce the need for irrigation, and that is why the next section attempts an accurate calculation of the annual line losses in Sonepat, taking into account the seasonal variations in demand.

Equipment failures are most common in the lowest level of the distribution system - typically in the 11 kV/440V transformers. This is because the load is most spiky at the feeder level. Additionally, as one goes up the hierarchy of the network, the capacity burden on higher voltage substations reduces because feeders emanating from a single substation are less likely to have coincident peaks. In fact, agricultural regions tend to have higher coincidence factors than other sectors because irrigation pumps are utilized for long stretches of time during the same time periods to flood large fields, which tend to have the same irrigation habits in any particular geographic region serviced by a substation. Therefore the stress on 11 kV substation transformers is also probably higher than in urban regions.[42]

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[41] Northern Regional Electricity Board, Pg. 2

[42] This fact was corroborated during fieldwork - distribution transformers are replaced at an unusually high rate in Sonepat, Haryana

Unfortunately, the quantification of the resulting T&D costs requires more definitive data on load patterns than was available for this analysis, and has therefore not been attempted. In the next section, the energy losses in feeders have been calculated for various load factors for incorporation into the production cost simulation. Transformer losses along with the losses in the primary (11 kV) distribution system have been calculated separately.

4.4.4 Methodology of Loss Calculation

The accuracy of an energy loss calculation depends directly on the granularity of the load data available. For this study, a very limited amount of load data was available. This is because local officials do not keep a record of load patterns for the 440 V feeders. Table 4-5 shows the peak demands for the loads and the number of connections of each type of load. The annual load variations were estimated based on the assumptions made about the daily and monthly variation in loads in Section 4.3.1. The following data was the extent of the information available for the distribution system of Sonepat .

Table 4-5: Distribution Transformer Characteristics (Power Factor = .7)

Type	Number	% of Total	Rating (kVA)	Power per LT[43] (kW)	Total (kW)
I	139	32.18	25	17.5	2433
II	15	3.47	40	28	420
III	5	1.16	50	35	175
IV	148	34.26	63	44.1	6527
V	125	28.94	100	70	8750
Total	432	100	26149		18304

The above table gives an indication of the technical potential for power delivery in Sonepat. With a power factor of .7, which was recommended by the Chief Engineer of the region, the transformers can support a peak load of 18.3 MW. From the load data in Table 3-3 we know that Sonepat has a total demand of 23 MW. The peak of the system probably would not be as high as 23 MW - nevertheless, the fact is that the distribution system barely has the capacity to support

[43] LT = Low Tension - refers to 440 V , 3-phase distribution feeders

the existing load. With an expected growth in demand of 10% and minimal capacity additions planned, regular transformer failures would be expected.[44]

Photovoltaic generation would generate power for the most part at the site of the load. Thus, an adequate comparison with conventional electricity must consider the loss in transmission and distribution right from the point of generation to consumption. The following methodology was adopted to calculate the percentage loss for every kilowatt-hour traveling the T&D system in Haryana to the district of Sonepat .

As shown in Chapter 2, Figure 2-2, a 132 kV high tension transmission line gets stepped down to 11 kV and then 440 V in the secondary distribution system. For a point-to-point path for power from the source to Sonepat, a loss factor 'X' can be constructed such that for every kWh of demand, a generator has to actually supply 1/(1-X) kWh of energy. This can be accounted for directly in the economic cost of bearing losses by multiplying the variable cost of power by 1/(1-X).

This loss factor can be written as:

$$X = y_1 + (1-y_1)*y_2 + (1-y_1)*(1-y_2)*y_3 \qquad (4.1)$$

Where:

y_1 is the percentage loss on the 132 kV line

y_2 is the percentage loss on the 11 kV (primary distribution system)

y_3 is the percentage loss on the 440 V (Low Tension feeders)

y_3 comprises the largest and most underestimated component of the three. Hence, considerable effort has been put into quantifying these losses to the best extent possible based on available data. The high tension loss percentage was taken from estimates of the Haryana State Electricity Board. Losses in the primary distribution system have been calculated using a software package developed at TERI, New Delhi.

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[44]Corroborated by Chief Engineer, Samarbandh Division, Sonepat in June 1994.

Since no information was available as to the loading of the individual feeders or regarding the locations of loads on the feeders, a simplified configuration of the distribution system and the distribution of load on the feeders was created with the following assumptions[45]:

1) The load configuration of a single LT feeder was approximated to be equally spaced loads along a feeder, which could then be treated as a concentrated load at the end of a feeder, one-third the length of the original[46]. (See Figure 4-8 and 4-9);

2) The feeders were assumed to be of equal length of 2.15 km. This figure was obtained by dividing the total length of the LT distribution system (930 km) by the number of distribution transformers (432);

3) Loads were assumed to be linearly proportional to the ratings of the distribution transformers. This fact was used to improve the accuracy of the loss estimates by weighing the losses on the different types of feeders by the number of such feeders in the system;

4) It was assumed that all LT feeders had the same proportion of domestic and agricultural demand on them, and that all 11 kV feeders had an equal proportion of different types of transformers;

5) All tubewells were assumed to be of the same rating (hp), since no information was available on the breakdown of the number of different types of tubewells. This figure was derived from the total demand from tubewells in the area and the number of tubewells present (Table 3-6);

6) The most crucial variables in the calculation, the power factor and load factor, were recommended to be .7 and .6 respectively. Sensitivity analysis was performed on the losses for

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[45]Adapted from World Bank Energy Department, "Energy Efficiency: Optimization of Electric Powerand Distribution System Losses", 1982

[46]Ibid, Pg 26

this value of the power factor. The load factor was varied based on the derived load curves in order to calculate average annual energy losses;

7) The commercial and industrial sectors were left out of the analysis because of the minimal contribution to demand of the former, and the low prevalence of the latter on LT feeders.

Using the following equations below, and assuming that the line-to-line voltage at the distribution transformer was 440V, the current and voltage drop in the feeders were calculated iteratively. With this current and the power factor the I^2R line losses and the reactive losses were calculated. The line losses were multiplied by three for the three phases.

$$V_{ref} = V_{load} - V_{drop} \qquad (4.2)$$

$$V_{drop} = I.R.\cos\theta \qquad (4.3)$$

$$I_L = \frac{kW}{\sqrt{3}V_{ref}}$$

Where $\cos\theta$ = Power Factor

I_L = Line Current

V_{drop} = Voltage drop across feeder

V_{load} = Voltage at the load

V_{ref} = 440 V at the transformer

Figure 4-8: Assumed Configuration of LT feeder - (Equally Spaced Uniform Loads)

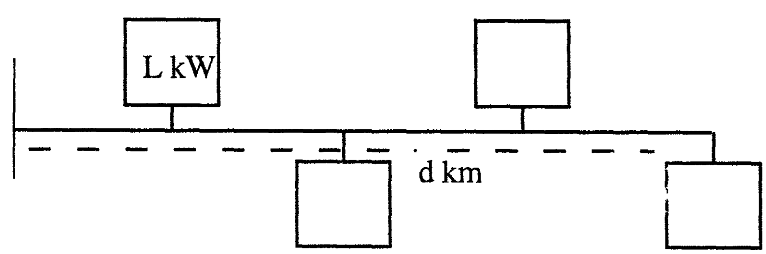
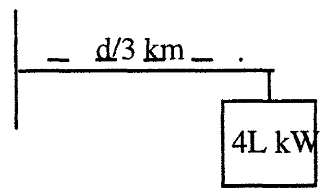


Figure 4-9: Resulting Simplification of LT feeder



4.4.5 Analysis

The table below shows the estimated average load from tubewells and domestic connections on the different types of feeders. The estimated load uses the assumption of 80% efficiency of tubewell pumps.

Table 4-6: Estimated Load on Individual LT Feeders

	Tubewells			**Domestic Connections**			
Type	Avg. Number	Max. Load (W)	Est. Load (W)	Avg. Number	Max Load (W)	Est. Load (W)	Total (W)
I	2.8	13859	11087	10.7	6311	5049	16136
II	4.5	22174	17740	12.3	7279	5823	23563
III	5.6	27718	22174	12.7	7477	5981	28156
IV	7.1	34925	27940	12.8	7562	6050	33990
V	11.2	55436	44349	22.4	13203	10562	54911

Using the equations (4.2 - 4.3), different loss percentages were calculated from different power factors and load factors.[47] Below is a sample output of the iteration and calculation (The adjusted load refers to the total load adjusted for a the load and power factor. In this example, power factor = .65, load factor = .6).

To emphasize, the final weighted loss represents the line and reactive losses only, and not the transformer or imbalance losses. Sensitivity analysis was conducted on the power factor, since it was not known with certainty. Losses are calculated for different load factors, which vary with the time of day, and incorporated into the production cost model.

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[47] Feeders are made of steel-reinforced aluminum, with a resistance of .9352 Ω/km at 20° C.

Table 4-7: Calculation of Distribution Losses

Adjusted Load (W)	Voltage drop (V)	Current (Amps)	3-phase loss (W)	Total Demand (W)	Loss %	Wtd. Loss(%)
14.898	8.70	19.94	800.67	10484.10	7.64	2.46
23.836	14.09	32.31	2101.97	17595.46	11.95	0.41
29.795	17.77	40.74	3341.80	22708.66	14.72	0.17
37.542	22.65	51.93	5430.30	29832.54	18.20	6.24
59.590	37.26	85.43	14692.43	53426.15	27.50	7.96
						17.24

Table 4-8: Sensitivity of Distribution Losses to Power Factor and Load Factor

LF/PF	0.7	0.8	0.85	.95
0.6	15.30	12.25	11.04	9.089
0.7	17.64	14.23	12.86	10.631
0.8	19.94	16.19	14.67	12.187

Table 4-9: Transmission and Primary Distribution Losses

T&D Component	Loss Factor
132 kV	4%
33 kV	4%
11 kV	4 - 6%
	(PF=.7 - .95)

The transmission losses were assumed constant. Since an improved power factor in the secondary distribution system would reduce the reactive burden on the primary distribution, 11 kV losses decrease to 4% for a power factor improvement to .95. Using Equation 4.1, the total T&D losses for a sample of load factors and power factors are shown below.

Table 4-10: Total T&D Losses

LF/PF	0.7	0.85	.95
0.6	26.62	22.94	19.56
0.7	28.65	24.51	20.93
0.8	30.64	26.08	22.3

4.4.6 Results

An improvement in power factor reduces distribution losses by almost 50%, and total T&D losses by over 25%. Losses decrease by the square root of power factor improvement, so that diminishing returns are achieved for further power factor improvements. The fact that losses can get as high as 12% in the distribution system alone even with a power factor of .95 indicates that the poor design of the distribution system - i.e. lengthy, over-loaded LT feeders - limits the capacity to eliminate losses, short of upgrading the entire secondary distribution system to a higher voltage level.

4.4.7 Power Factor Improvement Cost

We have seen that losses vary considerably with power factor. An obvious way of increasing capacity without building any is to reduce losses and increase voltage levels through the installation of shunt capacitors in the distribution system. Since losses impact the value of PVs considerably, the avoided costs for PVs have been calculated for different (improved) power factors. For a fair assessment of the change in avoided cost, the cost of this improvement must be incorporated in the analysis.

Below, the cost of improving power factor at the primary distribution level have been calculated. The purpose of this calculation is to get a rough idea of the amount of reactive compensation required in Sonepat, and then calculate the impact on avoided costs of PVs. An entire thesis can be written on the optimal configuration and choice of capacitors types that minimizes cost. Furthermore, in order to prevent overcompensation at different lower load levels, the right mix of fixed, switched and voltage-varied capacitors are required. Such an analysis is not relevant to the issue at hand.

Fixed capacitors are usually chosen to provide the compensation required for the minimum reactive load of the feeder it is connected to[48]. The following figures show the reactive compensation required for an existing power factor of .7.

Table 4-11: Reactive Compensation (kVAR) Required per 11 kV Feeder

LF/PF	.8	.85	.9	.95
.4	304	450	608	777
.9	684	1013	1367	1747

LF: Load Factor PF: Power Factor

For the above requirements, it was assumed that two capacitors, one switched and one fixed, of capacity 600 kVAR would be sufficient to improve power factor on one 11 kV feeder up to .9. The area studied in this thesis has six such feeders (See Section 2.3.1). With a cost of Rs. 89,500 ($2,887) and Rs. 212,330 ($6,849) each, an assumed lifetime of 10 years, and the same financing scheme in Table 4-16, *the cost of power factor improvement per kWh in Sonepat amounts to Rs .002/kWh ($.000077/kWh).*

In other words, it would cost absolutely nothing to improve power factor to .9. How significantly this improvement affects loss reduction and the value PVs remains to be seen. This rough calculation shows that no economic reason exists for not installing shunt capacitors in rural distribution systems.

4.5 Generation Data

4.5.1 Existing Capacity Mix

The reproduction of the capacity mix of Haryana is very important to portray an accurate reflection of the required capacity to meet suppressed demand and indirectly to calculate avoided costs of PVs. One of the reasons why the per unit avoided costs are high in India is that plants operate at a very low capacity utilization, mostly because of high maintenance and low availability, and sometimes because of the absence of least-cost planning in SEBs.

[48] Gönen, Turan, "Electric Power Distribution System Engineering", Pg. 400

Table 4-12: Haryana's Generating Plants (1991)

Plant Name	Fuel Type	MW	MWh	Cap. Factor
Bhakra	Hydro	454	2,140,400	54%
Dehar	Hydro	317	1,027,100	37%
Pong	Hydro	60	268,000	51%
B. Suil	Hydro	55	203,300	42%
WYC	Hydro	48	285,300	68%
Salal	Hydro	75	357,100	68%
Faridabad	Coal	165	626,800	43%
Panipat	Coal	650	1,430,800	25%
IP	Coal	62.5	260,300	48%
Singrauli	Coal	200	1,043,500	60%
Anta	Gas	25	152,700	70%
Rihand	Gas	65	207,300	36%
Auriya	Gas	38	196,300	59%
Purchase*	Hydro/Coal	-	92,200	-
Atomic Power Project*	Nuclear	15	43,900	33%
TOTAL		*2214.5*	*8,291,100*	*43%*

* Items omitted from analysis because of lack of information and minimal impact on results

Data for the breakdown of generation capacity was obtained from the annual report of the Haryana State Electricity Board (1991). The capacity factors were inferred from the total generated output for all the plants taken from the same source. Haryana shares most of its power with neighboring states. Only the coal plants belong to the state of Haryana, and the gas and hydro plants are jointly owned with neighboring states. The following table shows Haryana's share of the named generation plants.

The most important observation to be made is that of the capacity factors. Most of them are fairly low, while the larger plants have relatively lower capacity utilization than the smaller plants. This is probably an indication of the lower efficiency and higher maintenance required of larger plants, both of which reduce their effective availability during the year. An overall capacity factor of 43% - which equals system load factor when supply equals demand - reflects the poor availability of dispatchables, and also corroborates the steepness of the load duration curve estimated in previous sections. Because of the supply deficit that exists, the true peak demand and total energy requirements are higher than the total installed capacity and generated output respectively. Load shedding significantly reduces total energy requirements seen over the year, and also shifts regional peaks to different times, thereby having the desired effect of flattening the system load curve. The actual load factor is therefore difficult to estimate based on generation figures. However, the point of load shedding is to reduce peak demand, and not energy, due to insufficient installed capacity, therefore one can assume that the absence of it would increase peak demand much more than it would increase total energy demand. The actual load factor would in fact be close to, if not lower, than the system capacity factor.

In order to reproduce the above capacity factors and their behavior under forecasted demand growth in the analysis, the relative merit order within the generation mix and their availability was required. However, the relative merit order could not be ascertained from the above capacity factors, since one cannot distinguish between plants that operate for part of the year from those that operate continuously with limited availability. The modeling parameters used to restrict plant availability were forced and planned outages. The following outage rates were assumed, based on estimates of the Haryana Electricity Board. High outage rates were chosen for the coal plants to reflect the average plant availability of around 73% in 1991-92. This is a reasonable assumption, as is evident in the unusually low capacity factors of the two largest coal plants in Haryana, Panipat and Faridabad. It is highly unlikely that over 700 MW of coal be used as peaking plants, hence their limited availability had to be the cause of their poor utilization.

Table 4-13: Outage Rates of Plants

Plant Type	Planned Outage (%)	Forced Outage (%)
Hydro	10	15
Coal	10	25
Gas	10	15

4.5.2 Cost Assumptions

Accurate information on the operating costs of existing plants is difficult to obtain and verify. For the existing plant mix, the main goal of allocating costs was to produce a realistic value for the aggregate cost of generation that was consistent with SEB publications, rather than aim for an accurate breakdown of costs. It was assumed that the highest costs incurred were for operation and maintenance (O&M), and fuel costs for the thermal plants. The O&M figures were adjusted to reflect the actual cost of power reported by the Haryana SEB of Rs. 1.15/kWh ($.037/kWh) in 1991-92.

Table 4-14:Plant Characteristics

Plant Type	Variable O&M ($/kWh)	Fixed Cost (NPV)[49] ($/kW.Yr)	Fuel Cost[50] ($/MMBTU)	Heat Rates[51] BTU/kWh
Coal	.002	75	1.53	11,000
Gas	.0015	15	4.0	10,000
Hydro	.0015	81	-	-

(1991 dollars)

4.5.3 New Generation Technologies

Care was taken to reproduce the current generation mix in Haryana in order to obtain realistic figures for the total cost of generation. The avoided cost of PVs, however, depends primarily on the costs of new plants, since any capacity value credited to photovoltaics would come from avoiding new investment. Since PVs displace generation from peakers and possibly intermediate plants, older plants that get pushed up the dispatch order by new, more efficient plants may contribute to the avoided generation costs of PVs.

The dominant and most important component of the cost of new plants is their capital cost. The choice of capital costs used in planning is almost entirely a policy choice, and has less to do with the state of technology available. Since the value of PVs lies in the deferral, if not the avoidance, of investment in large, centralized plants, the characteristics of current investments in

[49] Discounted, annualized over 25 yrs - includes depreciation, interest payments and fixed O&M costs

[50] Obtained from the Kelkar Committee Report, Govt. of India, 1990

[51] At 100% loading - performance degrades with lower utilization

capacity expansion should determine the avoided costs that ought to be used in planning. However, with the influx of foreign investment throughout the country and the plethora of RFPs (Requests For Proposals) brought to the table, no one defensible set of costs can be assumed. Doing so for this analysis would therefore be imprudent. The costs of a typical public plant are fairly well established, but using these costs would ignore the ongoing developments of the power sector. Besides, most of the State Electricity Boards, including that of Haryana, simply do not have the revenue to re-invest in new capacity, and are most likely to seek private investment in power, as is evident in current trends.

A range of capital costs - $750/kW to $1250/kW - have therefore been used to ascertain the impact of their variation on the benefits of PVs. The heat rates and the O&M costs were reduced to reflect the higher efficiencies, both technical and operational, that would be present in private plants. Variable O&M, and outage rates were kept the same as for existing plants.

Table 4-15: Fixed Costs of New Plants

Capital Cost $/kW	Fixed Cost (NPV) $/kW.Yr
750	129.6
1000	169.4
1250	209.3

Table 4-16: Finance Data

Debt:Equity Ratio	4:1
Return on Equity	15%
Interest on Debt	8%
Insurance	2%
Utility Discount Rate[52]	9.5%

All costs calculated in this model are treated as levelized annual revenue requirements (LARR), including variable costs. See Appendix 3 for a complete mathematical description of the financial calculations in the simulation.

[52] Discount rate used = weighted cost of capital. See Appendix 3

4.6 Uncertainty Modelling

Three forms of uncertainty exist in a production cost model involving intermittents; uncertainty in load, unforeseen outages of dispatchable power plants, and uncertainty in the intermittent output. In this analysis, only the latter two have been modeled, because of the lack of any reliable data estimating load uncertainty. The probabilistic representation of solar output was in the form of hourly Gaussian distributions for a typical day in each month of the year. The forced outage rates of power plants represent their uncertainty. Two elements of the analysis utilized this uncertainty:

1) ELCC: An ex ante, analytic calculation of the LOLP combined the uncertainty in solar insolation and outages of dispatchables in order to determine the load carrying capacity of a given penetration level of PVs. Appendix 2 describes in detail the calculation of LOLP. Appendix 1 describes the available solar insolation data;

2) The avoided energy costs depend on the level of output of the PV system. In order to obtain a distribution of the range of energy costs possible, the Monte Carlo method was used to simulate random annual patterns of solar insolation. In effect, this model represents a time-series simulation of a PV system, and therefore encapsulates all possible performance levels, and their likelihood. Appendix 4 explains the implementation of uncertainty in the production cost model.

4.7 Computer Model Used

The power planning tool SUTIL was used to develop this production cost model[53]. This tool incorporates renewable sources of energy in a traditional load model, using the standard procedure for economic dispatch and LARR costs. The following significant functional enhancements were necessary to incorporate the new developments of this methodology.

i) A Monte Carlo simulation was built around the economic dispatch model to allow entry of probabilistic data on renewable performance and, optionally, load characteristics.

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[53] See Johansson et al. for a complete description of the software, Chapter 23

ii) The load representation had to be modified to represent losses and their avoidance by distributed generation.

iii) The tool was modified to distinguish between new capacity additions and the existing generation mix and their different costs.

See Appendix 4 for a visual description of the new production cost model in SUTIL.

4.8 Results

4.8.1 PV Performance

MEAN: 229,000 MWh (100 MW Penetration)

STD. DEV: 6,236 MWh

Figure 4-10: Sample Distribution of PV Performance

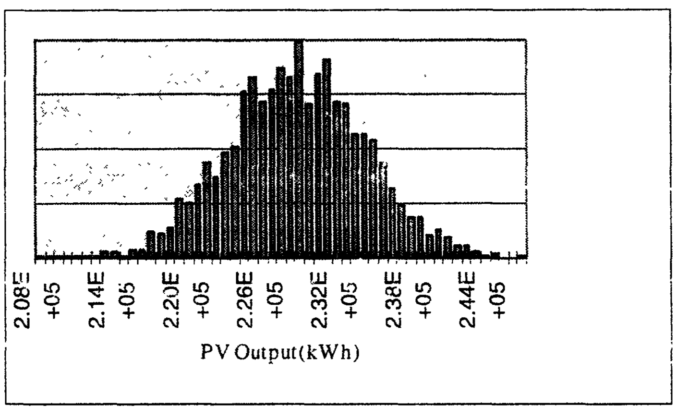

Table 4-17: Results of Capacity Factor of PVs

+ 1 Std. Dev	Mean	-1 Std. Dev
26.9	26.2	25.4
+2 Std. Dev	Mean	- 2 Std. Dev
27.6	26.2	24.7
Best Case		Worst Case
27.8		23.7

The above figures display the technical performance of photovoltaics in the region of New Delhi, and are therefore a reflection only of the geographic suitability of photovoltaics. A mean capacity factor of 26.2% was obtained, with a range of 24.7 to 27.6, within a 98% confidence interval. The distribution is approximated to a normal, with a 51% likelihood of an output greater than the mean. The value of capacity factors is fairly high, considering that the analysis has assumed the simplest cell technology (thin film polycrystalline cells) with a fixed tilt technology that does not absorb the maximum level of radiation that concentrator or tracking systems are capable of absorbing. Furthermore, since the insolation data used reflects thirty year averaged data, one can interpret the range of results as a time-series simulation, and therefore expect the poorest possible performance from the worst case scenario of 23.7 shown in Table 4-16. The value of having such a range of performance lies in the freedom of choosing the level of performance in making investment decisions based on the degree of risk aversion of the decision-maker.

The most important cause of the favorable performance characteristics observed is the favorable solar insolation characteristics of the region. In addition, the implementation of a sophisticated solar insolation model (See Appendix 1) that incorporates radiation from circumsolar diffusion and ground reflection also improved performance. In a true time-series analysis, other factors leading to the degradation of cell efficiency, such as the wear and tear from wind and the monsoon rains, and the poor maintenance of modules should be modeled in order to obtain an accurate performance trend. The only factor contributing to cell degradation that was modeled was temperature. Nevertheless, one can claim with a fair degree of certainty that from a photovoltaic investor's point of view this location would be very favorable to the deployment of photovoltaics.

4.8.2 ELCC (Capacity Credit)

The capacity value of photovoltaics is difficult to justify and estimate, especially with the inclusion of a non-dispatchable. The justification depends on the institutional and policy context in which photovoltaics are being evaluated. Section 3.2.3 explored the need to assume demand growth and the necessity of capacity expansion in order to justify incorporating capacity value in the analysis. The method of measuring ELCC used here is the increase in load in the top 100 peak hours that can be sustained by a fixed penetration of photovoltaics such that reliability is maintained at the same level prior to their deployment. Conversely, this is equivalent to the reduction in planned capacity allowed by the penetration of photovoltaics with the same reliability criterion and a fixed demand. The difficulty in estimating this figure is two-fold.

Firstly, the effect of relatively small capacity additions of photovoltaics - an inherent characteristic of small-scale grid-connected distributed systems -on the reliability of a much larger power system at a system-wide, planning level is difficult to discern. This problem was surmountable for the case of rural Haryana, since over 40% of the electricity demand comes from agricultural areas with characteristics similar to those of Sonepat, and therefore the total demand seen by the SEB is large enough to have a discernible impact on reliability. The sensitivity of reliability to different power factors, however, did have only a marginal effect. In the generic case, an arbitrary level of penetration would have to be chosen such that meaningful results are obtained.

The second problem arises from the characterization of photovoltaic output so that its effect on reliability can be accurately determined. When an analytic representation of hourly PV output does not exist, the choice of capacity credit for the peak hours of demand becomes a policy choice, dependent on the risk-averseness of the decision-maker. Measurements from a particular year are often used for this purpose, but this does not adequately characterize a long-term solution, especially in geographic regions with wide fluctuations in annual weather patterns. Given a probabilistic representation of hourly data, however, an accurate analytic solution can be found for the LOLP, and therefore for the ELCC. For this analysis, probabilistic hourly data was available, hence an analytic solution was sought. The mathematics of the calculation of LOLP has been described in Appendix 2 for the case where normal distributions of hourly PV output are available. The following results were obtained within a margin of error of 5%.

Table 4-18: ELCC of PVs in Haryana

Power Quality	ELCC
No Losses	60%
PF=.95	70%
PF=.85	72-73%
PF=.7	75%

4.8.3 Total Quantified Benefits

For a Penetration level of 100 MW:

The high and low refer for the rest of the analysis to the bounds around the mean containing a 95% likelihood. The table and histogram above assumes a capital cost of $1000/kW, and shows the relative contribution of variable and capital cost to the value of PVs.

Table 4-19: Breakdown of PV benefits for different Power Factors

	Fixed $/kW		Variable $/kW	
		High	Mean	Low
0.7	135.5	91.8	88.8	85.8
0.85	127.1	86.0	84.2	82.8
0.95	118.6	83.3	80.3	77.4
No Loss	101.6	57	54.9	52.9

Figure 4-11: Dependence of PV value on Power Factor, Losses

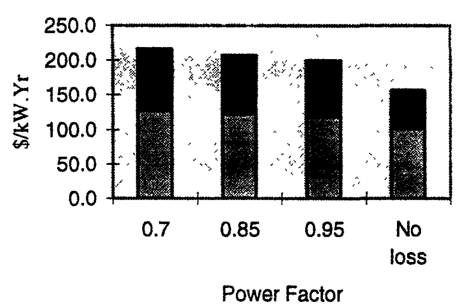

Table 4-20: Total PV Benefits ($/kW.Yr) for Varying Power Factor and Capital Cost

Capital Cost	Power Factor	High $/kW.Yr	Mean $/kW.Yr	Low $/kW.Yr
$1000/kW	0.7	227.3	224.3	221.3
	0.85	213.1	211.3	209.9
	0.95	201.8	198.9	196.0
$750/kw	0.7	195.4	192.4	189.4
	0.85	183.2	181.4	180.0
	0.95	174.0	171.0	168.1
$1250/kw	0.7	259.2	256.2	253.2
	0.85	243.0	241.2	239.8
	0.95	229.8	226.8	223.9

4.8.4 Discussion

The above table present the most salient results of this analysis. They represent the total quantifiable benefits of deploying grid-connected photovoltaics in agricultural Haryana, and include a capacity value, an avoided energy cost, and a contribution to both capacity and avoided energy value from the presence of demand and energy T&D losses.
Several important observations can be made.

- The value of PVs lies primarily in the displacement of peaking power for Haryana, that is, for plants that would run under a capacity factor of 30% in the absence of PVs. This means that the most cost-effective way of meeting demand growth in agricultural regions in Haryana is to install small-scale, peaking plants that have lower capital costs - relative to base load plants - and can be load -following. The implication for policy is crucial. If Haryana is to follow a least-cost planning approach, it must seek the most appropriate capacity mix to meet demand growth. The current inexperience and eagerness to take advantage of a privatized, competitive market for generation has led many state governments to consider RFPs for very large-scale projects, which this study indicates might not be the most cost-effective path for a state like Haryana that requires peaking capacity to meet growth in 40% of its demand mix.

• For a constant power factor of .7, which is the probable status quo in the region of study, the average benefits of PVs falls in the range of $192.4/kW.Yr to $256.2/kW.Yr (Rs. 5,964/kW.Yr - Rs. 7,942/kW.Yr) for the shown range of capital costs (Rs. 2.33 - 3.88 Crores/MW).[54] The lower value assumes an avoided investment, or deferral, in a peaking plant, which would mean that the SEB would base decisions on a least-cost planning approach. This can also be considered the economically efficient break-even cost of PVs. An increase of over 20% in cost is seen with a capital cost of $1250/kW. Although the use of such a high capital cost may seem unreasonable from an economic standpoint, this reflects a political reality. Enron proposed a capital cost of almost exactly $1250/kW in the controversial Dabhol project in the state of Maharashtra, whose fuel source was Liquified Natural Gas (LNG). Although the State Government initially rejected this contract on the grounds of cost, the capital cost was only one of several other terms of the contract, specifically concerning the tariff structure and the guaranteed sale of power, that rendered the unit cost of power very high. One therefore cannot rule out the possibility that future projects with similar capital costs may be approved, so long as other terms of the contract appear favorable. The cost of installing and operating large foreign power plants in India can only be estimated, since little prior experience exists against which to compare new proposals.

It is useful to place these numbers in perspective, and compare them to other significant results of the value of grid-connected photovoltaics. The most well known study in the US is that of the 500 kW Kerman PV plant by PG&E in California[55]. The importance of this study lay in the quantification of several non-traditional benefits of grid-connected PVs, which have been discussed in previous chapters here. The results show that the benefits fall within a range of $293/kW to $424/kW (1995 $), depending on assumptions of capacity credit for generation and distribution equipment. Of this, about 45% of the value comes from non-traditional benefits, and almost half of this comes from energy savings. The only component that can be directly compared to those obtained in this analysis are the energy savings. In both cases a similar

[54] 1 Crore = 10 million

[55] Hoff, T., et al., "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project", 1994

capacity factor of 25-26% was obtained, and both use the avoided fuel costs of a gas plants. Still, the fuel savings in the Kerman project are $132/kW - translated to 1991$ assuming a 2% rate of inflation in the US - compared to only $88.8 in the Indian case.[56] (Henceforth an unspecified reference to PV values in this analysis will assume a power factor of .7 and a capital cost of $1000/kW). The difference arises most probably from the high penetration level of PVs in this study. The first megawatt of PVs would probably have as high an energy value as in the Kerman case. A difference in the financing assumptions, such as the discount rate, could also contribute to the difference, although this information was not available in enough detail for the Kerman study for an explicit comparison. Since gas prices are comparable, if not more expensive in India, fuel prices would not contribute to the difference.

The most significant difference in the two studies lies in the capacity value of PVs. Because of the high losses and the peak-intensive operation of PVs, the capacity credit constitutes over half the total value in India ($135/kW). In the Kerman case, the best case scenario estimates a capacity value of only $53/kW (1995$), and a value of only $12/kW under the regulatory assumption that PG&E requires no additional generation capacity. This fact is a reminder that, despite economic considerations, the choice of capacity credit is ultimately one of policy. Especially in light of the assumptions made in this analysis of the need to expand capacity, the value of PVs depends critically on the motives of the State Electricity Board.

Significant insight can be gained into the value of the unquantified benefits in this study by looking at the value assigned to analogous benefits in the Kerman study. The only non-traditional benefit quantified in this analysis is that of losses. Despite the knowledge that T&D avoided costs, especially distribution equipment costs, are probably very high in rural regions for reasons discussed earlier, the lack of data addressing their monetary value prevented their incorporation in the analysis. In the Kerman study, in addition to T&D avoided costs, dollar values are assigned to reliability, environmental benefits, loss savings and minimum load savings. The savings in distribution equipment at a feeder level is indisputably the most applicable and highest in proportion. *If one assumed a T&D savings of the same proportion as in the Kerman study, the value of PVs in rural India goes up by 30% to $291/kW.* The technical validity of the savings

[56] Note that all figures in this thesis have been calculated in 1991$

arose from the cooling of transformers that resulted from deploying PVs, thereby deferring replacement/maintenance and increasing their effective capacity. In the Indian case, field work revealed that peak demand reduction would prevent permanent damage, rather than defer replacement, of the transformers. Thus, the use of figures from the Kerman study represent a conservative estimate of T&D savings.

• Earlier sections discussed the exacerbation of power losses due to low power factors, and the possibility of creating additional capacity by improving the power factor. Economically, this is a sound solution since, as was found in Section 4.6.7, the per kWh cost of improving the power factor to .95 is practically insignificant. The question remaining is how much artificial capacity can the reduction of losses through power factor improvement create. Table 4-19 answers this question by showing the benefits of PV for different power factors. For any of the capital cost assumptions, an improvement from .7 to .95 results in a decrease of about 11% in the avoided costs. Note that the same power factor improvement results in a 25% reduction in total T&D losses, and a decrease of over 50% in distribution losses alone. Clearly, the net economic effect that filters up into the system cost is much lower than the actual loss improvement. Even with a power factor of .95, the economic benefit of PVs vary from 171/kW.Yr to $226.8/kW.Yr. *The implication here is that losses are significant even with an optimal power factor. This indicates that the infrastructure of lengthy, low voltage lines coupled with high demand are the chief cause of high losses.* The avoided energy cost in the scenario without losses is only $55/kW, compared to $80 and $88/kW for a power factor of .95 and .7 respectively. (The no-loss figures do not represent any realistic scenario on their own. They have been shown just to illustrate the high contribution of losses, even at high power factors). It is important to emphasize that the avoided costs represent a conservative estimate, because of the inability to quantify the avoided capital costs of distribution equipment.

• Although not shown in the above results, the total system cost obtained for the expansion plan is 5.1 c/kWh (Rs 1.53/kWh) compared to a cost of 3.5 c/kWh (Rs 1.15/kWh) without any capacity expansion, at current costs. The 50% increase comes from the sudden increase in fixed costs from new, capital-intensive plants, compared to the old, existing plants that have little depreciated value. Although it may seem that the cost of peak power in the system, as reflected in the avoided costs of PVs, are only about three times the average cost, this is not the case. The avoided costs of PVs represent the average of 100 MW, or 50 MW of PV capacity. The true cost at the margin can only be captured by the value of the first megawatt of PV.

- An important objective of this analysis was to model the uncertainty in PV output and ascertain its economic impact on an investment decision. The performance of PVs already indicates that their capacity factor varies within 6% of the mean within a 98% confidence interval. Since the uncertain output affects only the variable costs, Table 4-19 shows that the value of PVs vary within less than 4% of their expected value. However, this does not reflect all of the costs incurred. If reserve margins are sufficient to buffer unexpectedly low levels of PV performance, existing (peaking) plants would compensate, and incur energy costs - an event that is characterized in this analysis. If not, the quality of power in the region would go down, and customers would face outage costs - an economic cost not modeled in this analysis. Thus, the utility does not necessarily bear the entire burden of uncertainty. What this analysis reveals is a range of probabilities of different output levels of PVs over time and the associated economic costs facing a utility, and indirectly shows the margin of error surrounding an investment decision. Using decision tree analysis, a policy maker can use these results to make a choice of technology based on his/her risk-averseness. A conservative planner would deploy PVs based on its poorest expected performance - by calculating its ELCC on that basis - and expect no significant decrease in reliability from an ex ante calculation. The range of economic uncertainty is, however, small enough that the risk-averseness of a planner might not affect the outcome of a decision concerning the choice of PVs, or the desired penetration level.

This chapter has analyzed the avoided costs of PVs so far. Although important, the economic potential of PVs is only one of many factors that will determine the viability of PV investments. The next chapter explores the remaining issues that need to be addressed, both from the point of view of a PV investor, and from that of policy makers in India.

5. Viability of PVs for Capacity Expansion

The previous chapters have studied the institutional, economic and the technical conditions of the power sector in rural regions of India and the ramifications of deploying distributed photovoltaics in these regions. Some of these conditions were incorporated into an economic analysis to attribute a numerical value to the benefits of PVs. Several assumptions regarding the planning goals of policy makers were necessary in order to justify the need for capacity expansion to meet rural demand. The economic objective of analyzing a least cost expansion plan with intermittents was separated from the institutional and political framework within which decisions concerning capacity expansion are made, and from the broader goals of policy that encompass it. This was important in order to isolate the economic arguments governing the selection of PVs, which are an important component of the decision making process. However, economic results serve little purpose on their own, especially in the context of evaluating avoided costs, since they ultimately result in a policy choice that may or may not derive from those economic considerations. It is no surprise that the numerical results obtained in the previous chapter vary greatly with factors that are influenced by policy, such as the attribution of a capacity credit to PVs, the estimated power factor of the distribution system, and the choice of technology adopted as an avoided alternative for peaking power.

The objective of this chapter is to place these results in a realistic context; in one that addresses the viability of grid-tied PVs in India from a policy perspective. Two different approaches are taken in discussing this. One builds on the heretofore applied approach of assuming the need for capacity expansion, and analyzes the technical and institutional requirements of grid-tied PVs for capacity expansion. PV deployment in India requires willing investors, who require price competitive PVs and a potential for profit, coupled with a healthy investment climate provided by domestic policy and supported by the credibility of the recipient government. From the investor's perspective, some of pertinent questions are: when, if at all, can PVs achieve cost-effectiveness, as defined by the results of this analysis? From the perspective of SEBs, what sort of offers and terms of contract would they need to provide for intermittents? What market structure and pricing mechanisms would be most attractive to PV investors?

The second approach to the policy analysis steps back and assumes a more holistic framework, such as the one introduced in the beginning of Chapter 3. In this, the broader view is taken of meeting the energy needs of rural regions in the most economically efficient manner. The analysis of the previous chapter reveals that the underlying assumption made of an implicit incentive to serve rural communities and the unusually poor condition of distribution systems in rural regions affect the attractiveness of distributed generation, or any form of capacity expansion, quite severely. Capacity value constitutes the bulk of the benefits of PVs, and the presence of losses and high T&D maintenance expenditure further enhance their attractiveness. The absence of a tariff structure and high losses create a demand growth that distorts the need for capacity expansion. This chapter will address the suitability of distributed PVs in alleviating the capacity deficit and the poor quality of power in rural regions. Other alternatives to distributed generation, such as load management, are discussed for their ability to target the root of the problems of rural power sectors more directly.

5.1 Viability of PV Investment

Distributed generating units have complicated technical requirements for connection to the grid because of their close proximity to loads. These technical requirements influence the operations and costs of PV systems. In order to see PV investments in India in the future, the economic potential of PVs will have to be complemented by a favorable investment climate offered by SEBs and a fourfold reduction of world PV prices in order to achieve cost-competitiveness. This section takes a look at these issues to see what form of pricing, management and ownership are best suited to create a technically and economically viable PV investment.

5.1.1 Economic Implications of Grid-Interaction of PVs

This section discusses the interconnection requirements that impact the economics of a PV system. Technical implications of operating a grid-connected PV system, such as the effects on power quality (voltage and frequency) and the dynamics of utility interaction (harmonic injection), are beyond the scope of this discussion. Grid-interactive PV systems demand certain equipment and modes of operation over and above conventional connection requirements in order to operate successfully. These requirements also change with different interconnection configurations, hence it is important to bring forth how these factors affect their deployment. Two important types of requirements pose challenges to planners.

Continuous Operation of Feeders

The condition of a distributed generating unit left connected to a distribution feeder with no main source of utility power is known as islanding. For a non-dispatchable distributed generator, loads may draw power beyond the capacity of the generator, and cause voltage and frequency to reach unacceptable values. A sudden cloud passage over an "islanded" PV system during peak loading would be an example of such an occurrence. In addition to the adverse effects of islanding on voltage and frequency, an out-of-synchronism reconnection following islanding can destroy the power conversion equipment of a PV system. The only safe option for the unit is to install protection equipment that disconnect it from the grid upon detecting a loss of grid power.

Clearly, if utilities expect to gain maximum utilization of an installed PV system, the practice of load shedding in these areas will have to be curtailed. This would represent a drastic change in the operation of rural power systems. It symbolizes a commitment to full power provision in those areas with distributed PVs, and increases the likelihood of load shedding in the rest of the system. Even in the absence of deliberate load shedding, if abnormal conditions occur often, such that the distributed units are forced to remain disconnected for large periods of time, the utilization again would drop. Both these conditions are prevelant in rural areas today, and can be expected in the future so long as supply deficits persist. *The effective capacity factor of the PV system in practice would therefore be much lower than the technical potential suggests.*

Protection Equipment

To protect against load fluctuations and abnormal conditions such as islanding, PV systems necessarily require protection systems to automatically isolate the unit from the grid upon detection of these abnormal conditions.[57] The number of connections to the grid complicate the requirements for protection coordination and for voltage regulation even further. For this reason, a study of the requirements for parallel generators in the Ontario Hydro Distribution system recommends only one point of interconnection per distribution feeder. [58] Complicated protection schemes also carry with them high costs and the need for expertise.

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[57] See Redfern M. et al.for a discussion on types of protection systems required for loss of grid protection

[58] Kundu, M., "Technical Requirements to Connect Parallel Generators to the Ontario Hydro Distribution Electricity System", Pg. 9

In an area with no prior experience with distributed generation and noticeably unreliable grid power. it would be prudent to select the simplest configuration. The advantage of more efficient loss minimization with a greater number of connections along the grid is therefore offset by their stringent, perhaps prohibitive, connection requirements.[59] A single plant also has the advantage of concentrating protection and inverter equipment at one node, thereby reducing the overhead of monitoring and possibly also the cost of equipment. The maintenance and response to failure of systems would therefore be superior, which would improve the quality of power to recipient areas. Both these configurations also have implications for the most appropriate ownership structure. The next section looks at this, and other institutional arrangements best suited for PVs.

5.1.2 Ownership, and Terms of Agreement

When, if at all, prices of PV technology drop to an attractive figure a few decades from today, the market for private power in India will have matured considerably. Without speculating about the resulting form of the private power participation -- a competitive bidding structure or standard utility offers -- some recommendations specific to the terms of agreement and management structure for PV investment can be made, which are necessitated by the intermittent nature of PVs, their localized, distributed deployment and their interconnection requirements discussed in the previous section.

Ownership and Management

The optimal configuration of PVs that minimizes losses (See Appendix 5) requires that individual panels, or sets of panels, be placed close to load clumps on a distribution feeder. The previous section showed that a simpler configuration of one PV plant on each distribution feeder, although bearing noticeable losses, might suit conditions of rural areas better. These two different configurations lend themselves to different forms of ownership and management. The former resembles rooftop programs commonly seen in Europe and USA. In this case, utilities usually install and maintain systems themselves.

With the current record of equipment negligence in rural areas, it is questionable whether SEBs could manage PV systems satisfactorily. Although grid-connected PV panels are designed to

[59] See Appendix 5 for discussion on the number of connections

require minimal operation, they need to be cleaned regularly to maintain efficiency, and in the likely event of inverter failures, they would require attention. A significant increase in administrative personnel would be necessary to maintain the number of installed sites required to meet the scale of deployment assumed in this thesis. One could consider the problem of management as just an anticipated increase in the O&M cost of the system. Therefore, the overall cost of installing and managing a more distributed PV system would be higher than for a more modular set up. But since the corresponding value (avoided costs) would also be higher, given the lower losses generated, one cannot easily ascertain which option would be preferable.

The second, more simple configuration, of installing one plant per feeder would suffer non-negligible losses, but would permit IPP ownership and operation. The advantages of this are the same as the advantages of private ownership of any power plant; a vested interest in the continuous, efficient operation of the plant, in maintaining a high power factor to minimize losses, and in ensuring the metering of energy usage to maximize revenue generation. Several indirect benefits result from IPP ownership of PV plants that overcome obstacles discussed previously arising from the neglect of rural areas. The recording of energy usage itself would allow SEBs to learn load patterns, and therefore determine, through an analysis similar to one in this thesis, the real avoided costs and their time dependence. Since an efficient power purchasing system sets the ceiling price of purchased power to the utilities' avoided costs, this would put a cap on the rate utilities should pay IPPs.

Clearly, one needs to zoom in and analyze these two options in more detail to determine the better solution. This would entail an accurate calculation of the losses in both configurations, the determination of the necessary protection equipment and their costs, and the difference in the rate of return awarded to an IPP vs. an SEB.

Buy back Structure

Most of the negotiation of a tariff/buy back rate will have to occur at the state level, just as is done with wind projects. Today, the role of the central authorities has been to back the lack of credit-worthiness of bankrupt SEBs in the early stages of privatization. The first eight approved proposals have been guaranteed a sale of power equivalent to an annual PLF of 68.5%, with additional returns for higher levels of generation. The sale of a fixed amount of power cannot be guaranteed for an uncontrollable, intermittent source of power. Even if guarantees were to be offered, they would have to be designed by the states based on their own climatological and load characteristics. Besides just the solar resource potential, this thesis has shown that the value of a PV system depends on the capacity mix of the state, its agricultural patterns, demand growth in rural areas, the average cost of power, and a host of other factors, all of which affect the design of the appropriate power purchase scheme and must be determined at the state level.

The central government can attract PV projects to India with financial incentives similar to those offered for wind farms in the past few years. These consist of a five year tax exemption, an allowance for 100% accelerated depreciation, and concessions on import duty for equipment[60]. From a financial standpoint, the tariff structure for wind and PVs can be practically the same. However, PVs will probably always be a more expensive technology than wind-turbines, and the sensitivity of their value to the optimal configuration of PV systems might merit a more careful derivation of their rates.

5.1.3 Photovoltaic Price Projections

This thesis has so far avoided a discussion of the costs of PV technologies. This is to prevent getting embroiled in a debate in which not only are there a vast range of technologies to consider, but also in which a multitude of opinions exist. The actual and projected costs of PVs are largely incidental to the point of this thesis, since the focus has been on identifying and evaluating the much less understood avoided costs of distributed generation. However, given that a numerical value for the benefits has been obtained, an interest in the actual feasibility of implementation requires a cursory look at least the trends of PV costs, if not their actual values. Clearly the values of benefits obtained above cannot be achieved at today's costs. PV module prices alone fall in the range of \$6/Wp[61], while the break even overnight cost in this analysis is around \$1.4-1.6/Wp. The question is whether any potential exists for the four-fold drop in costs that is required for them to become cost-effective.

The eighties saw a significant reduction in PV prices, primarily from advances in cell technology. Since then, market growth has stagnated and consequently prices have leveled off. Total PV production fluctuates around 60 MW per year. In order for significant cost reductions to

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60 Annual Report 1994-95, MNES, Govt. of India Pg 38

61 Kern, E., "PV Friendly Pricing Project", Ascention Technology, 1995

occur, several questions need to be answered. First, does the technical or economic potential for technology improvements or economies of scales exist. If so, can the PV market sustain the level of growth necessary for the commercialization of grid-connected PVs? How is demand growth correlated with cost reduction? Finally, is it feasible to create the necessary level of demand for a product that is currently far from competitive?

According to popular opinion amongst solar cell manufacturers, the industry is at a stage where several avenues for price reductions exist, but in order for any of them to be realized, an impetus in demand is required. Besides cell technology improvements, several advancements have been made in manufacturing and in finding innovative solutions to specific problems in the production cycle. The most significant change in the industry has been a shift in emphasis from component research to the development of the entire production cycle for PV systems. Module manufacturing techniques have improved. For example, Spire Corporation, USA, has developed an advanced stringing machine that takes silicon solar cells like a deck of cards and deals them out into different configurations that can be soldered together.[62] Other innovative module designs that reduce overhead capital costs include the development of frameless modules, and the use of inexpensive encapsulating materials. Manufacturing capabilities are prepared to cater to a diversity of end uses. This indicates a significant potential for high volume production.

On the component side, the manufacture of larger cells has allowed a reduction in material and labor costs. This facilitates the production of lower cost modules with a higher power concentration. AstroPower Inc., USA, ships cells of size 150 cm^2 and 225 cm^2, compared to the industry standard of 100 cm^2 to date. The costs of cells themselves constitute over 40% of total system costs, and remain a major price bottleneck. Higher efficiency cells reduce the demand for land area and system components, and hence can reduce the cost per kW installed, if commercialized. Laboratory experiments have demonstrated efficiencies of over 25% for terrestrial applications, but they are far from being commercialized.

The cost of the raw material to make cells (silicon) constitutes about 60% of the cell cost. The higher the grade of silicon, the higher the efficiency of the cells, but the more expensive they get. Today silicon costs $10 to $47/kg for high efficiency cells. However, Texas Technology claims

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62 "Advancing Photovoltaics", Independent Energy, March '93, Pg. 62

to have achieved 11% efficiency cells from metallurgical grade silicon for only \$1-2/kg[63]. Coupled with economies of scale for bulk production, these cells could bring down the cost by a factor of two.

Despite the fact that many of these figures represent only projections and estimates of performance from PV optimists, there is enough evidence to suggest that market growth can bring prices down. PV cells have the advantage of being ubiquitous. Given an initial impetus, the world market has the capability of sustaining itself once PV cells become price competitive in some niche markets. Price reductions will expand their competitive scope, thereby boosting demand and fueling further price reductions. The interesting question concerns the responsiveness of price to market growth.

Any significant future market growth will come from grid-connected applications, since most other PV markets are saturated. Based on market estimates and learning curve experience, a PV system developer, Ascension Technology in Massachusetts USA, estimates that an annual growth of 50% from 1995 to 1999 can bring the price of PV modules down to \$3.60/Wp by 1999. After that, the grid-tied market would be able to sustain itself. At an annual production of just over 2 GW in 2010, module prices could reach \$2.00/Wp in that year[64]. This report assumes that module prices for grid-connected applications are approximately 80% of the average price of modules, and will drop to 60% in 1999 based on these growth projections. Other estimates project a higher price responsiveness to demand. For example, Martin Marietta proposed a cost of \$2/Wp for commercialized applications of its CIS technology in 1994 that could produce cells with an efficiency of 14%.[65]

The general conclusion that can be drawn is that cell manufacturers need a period of guaranteed, growing, high volume purchases to induce any price reductions. Based on the estimates above, a demand of over 600 MW for PV cells would have to be generated in the next five years. Such an impetus could create a self-sustaining PV module industry, and lead to significant price reductions. Generating an "unnatural" level of demand for a non-competitive technology requires

63 "Photovoltaics Insider's Report", March 1992.

64 Kern E.

65 Ansari Z., "Metropolitan to make efficient photovoltaic cells in India", Business Post, 17 July 1994, India

subsidies or other incentives. This would require strong, consolidated international commitments to PV purchases. Such initiatives can be justified only if a sufficient guarantee exists not only for future price reductions, but also for a competitive advantage for PVs over other alternatives.

5.2 PVs - The Right Solution ?

So far, this chapter has continued the investigation of the potential for PV investment in India, building on the economic analysis to complete a comprehensive feasibility study from the perspective of a PV investor. Several important assumptions were made along the way concerning the requirements for the improvement of the rural sector, the proclivity of SEBs to seek PVs as a choice for new capacity, and the necessary technical conditions for their deployment. The rest of this chapter examines the viability of these assumptions with the intent of understanding and addressing the needs and conditions of the rural sector, and whether PVs address these needs suitably.

5.2.1 The Need for Tariff Reform

The most essential assumption in the economic analysis conducted has been that of the existence of incentives for SEBs to build capacity to meet rural demand. Without it, capacity planning for rural areas is a moot point. In fact, the status quo seems to indicate just that. The level of peak shaving, the lack of power factor improvement, and the poor planning of rural distribution systems -- manifested in lengthy, overloaded low-voltage feeders -- are all reflections of the neglect of rural areas. The concept of an obligation to serve is not written in law, and rural areas generate minimal revenues for SEBs. However, the growth of electricity consumption and sales in the agricultural sector and the doubling of the number of electrified villages in the past two decades indicate clearly that a motive *does* exist for the provision of electricity to rural areas (See Chapter 1). Political rhetoric and budget outlays in the Five-year Plans also cite the continued support for the development of rural electrification. In principle, given that it is a national priority to improve the productivity of the agricultural sector through the provision of electricity, the assumption that power planners need to think in terms of long term capacity planning for rural areas is reasonable.

The problem is that this political objective does not and cannot translate to a marginal cost approach to planning with the current tariff structure in the agricultural sector, which bears practically no relation to the cost of supply. In Section 3.1.2 the inherent coupling between pricing and LRMC planning was already stressed. Pricing of electricity in the agriculture sector is inextricably linked to the financial viability of SEBs, since agricultural demand represents a large component of the electricity consumption in over eleven states in India, and exceeds industrial demand in four of those eleven states[66]. The agricultural sector represents a large financial sink, and the current paucity of SEB coffers disallows any capacity planning for non-remunerative customers. SEBs do not recover their regulated 3% rate of return for several reasons, most of them linked to the subsidy to the agricultural sector. Often state governments do not compensate SEBs for the effective subsidy; cross-subsidies from the industrial and commercial sectors do not adequately cover the agricultural subsidy; and SEBs do not recover even those revenues expected from the agricultural sector, because of pilferage, lack of metering, and poor management. If the surge of proposals for private/foreign generation materialize, the average cost of electricity will rise, as this analysis has shown, and the financial burden on SEBs will worsen, not improve. As the cost of power increases, the incentive to curtail power to rural areas also increases, since every unit of energy consumed is lost revenue for the SEB. In other words, with the current tariffs, the cost of new generation is not passed on to agricultural customers, and therefore must be borne by the SEB. Clearly, current practices have a downward spiraling effect both on the financial viability of SEBs and the quality of power in rural areas, and are therefore counterproductive to the objectives of the state.

This is not to say that the subsidization of agriculture must be abolished. *The point here is that the nature of subsidization has economic ramifications that run counter to the national objectives of power quality improvement by removing any economic incentive for power provision in rural areas, and creates systemic failures that cost the system (and therefore the SEBs) more than necessary.* The cost of a subsidy to a state is usually justified by, and often equal to, the benefits accrued by the recipient. However, in this case, the costs far outweigh the benefits to farmers of limited, poor quality power. Simply stated, the current subsidy is an inefficient one. There is room to improve the net benefits accrued by the recipients *over time*, with a less expensive, but more efficient, subsidy.

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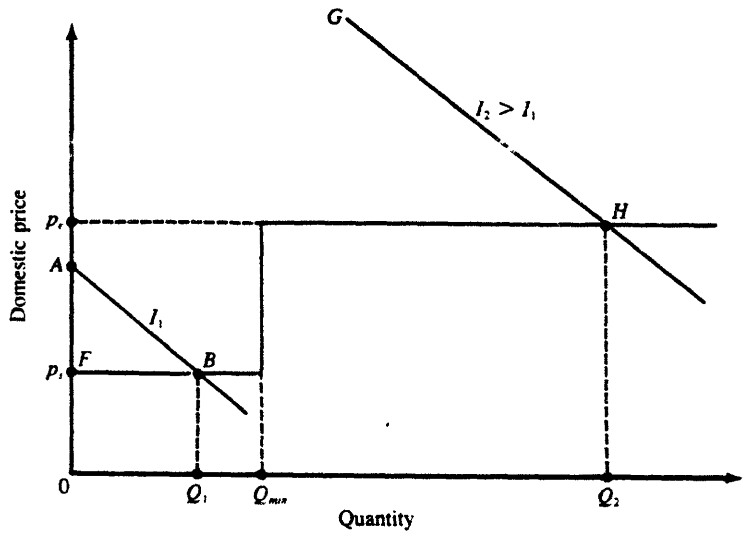
[66] Punjab, Haryana, Uttar Pradesh and Gujarat

A public enterprise with social objectives must necessarily have a minimum level of financial performance, usually in the form of revenue requirements, for its continued operation and financial viability. Classic economic theory in LRMC planning recognizes the need for deviations from strict LRMC pricing due to distortions and non-economic objectives, such as income redistribution. However, within a framework adjusted for these considerations, efficient pricing to improve resource allocation can be sought. Munasinghe describes the economic rationale behind subsidization of a particular social category. P_s represents the subsidized price, and P_e the price for average consumers[67]. The subsidized price captures the consumer surplus of the low-income consumers, which would have been unattainable at the unaffordable price of P_e.

Figure 5-1: Economic Basis for a Subsidy for Electricity



Munasinghe points out several factors that influence the design of the optimal price P_s, paid by the recipient of the subsidy, and the corresponding consumption level Q_{min}. Depending on the social value attributed to the benefits of electricity provision to rural consumers, the consumer surplus ABF can be multiplied by a weighting factor. Q_{min} must be chosen carefully to avoid subsidizing well-off consumers, and to meet the minimum electricity consumption requirements. Finally utility revenue requirements constrain the combination of P_s and Q_{min}.

The latter two points identify the failures of the subsidy in the Indian context. There is effectively no concept of a Q_{min}, since consumption cannot be controlled through price. As mentioned earlier, the agricultural subsidy effectively manifests as a per kW charge. Several SEBs do charge agricultural consumers a per kWh price, but because of implementation hurdles, such as the cost

67 Munasinghe, M., "Electricity Pricing - Theory and Case Studies". Pg. 68

of the rural infrastructure necessary to enforce such a pricing mechanism, these revenues are not always collected. As a result, no restriction based on financial constraints can be placed on Q_{min}. Load patterns are not recorded, because of a lack of metering equipment, and are therefore not incorporated into pricing policy. Without accurate load patterns, the shape of the demand curve AB of Figure 5-1 cannot be determined, and therefore an appropriate subsidy cannot be designed. In reality, Q_1 and Q_{min} lie close to Q_2. At this high level of subsidized consumption, the marginal cost of supply would be much higher than the price of the subsidy. Clearly such a subsidy is inefficient and untenable in the long run. At the very least, per kWh pricing is a prerequisite to limit and control consumption through price.

The fact that several SEBs do recognize and have attempted to implement a per kWh price may render the above analysis uninsightful. The crucial factor that cannot be overemphasized, however, is the consideration of future benefits accrued by the agricultural consumers. The SEBs bear the cost of the virtually free distribution of energy in rural areas today, and will inevitably pass them on to future consumers. If it is a political necessity to provide electricity to the agricultural sector, the state must also consider the ability for the SEBs to provide in the *future*. The states need to weigh the cost of investing in the rural infrastructure needed to develop a sustainable pricing structure against both the cost of wasted energy incurred today, *and* the less quantifiable, but potentially serious, costs of imposing further degradation in power provision and quality on future consumers.

Designing a more effective subsidy and proposing methods of tariff reform require the consideration of several other complex issues, such as political motives of policy makers, and the value of the electricity subsidy to the total cost structure of farmers individually, and to agricultural productivity. The breadth of such an analysis is well beyond the scope of this work. This discussion highlights the short-sightedness of the current subsidies and tariffs, and stresses need to control consumption in order to maintain the ability to provide power to rural areas in the future.

The production cost model of the previous chapter assumed an exogenous level of demand based on estimates of demand growth in rural areas. The analysis emphasized the per unit avoided cost of power for the purposes of calculating the value of PVs. This value incorporated some of the inefficiencies in the system, and therefore brought out the additional hidden costs borne by the state. The aggregate level of wasted energy, however, more accurately reflects the drain on SEB resources, and this depends on the aggregate level of demand.

Having discussed the necessity of controlling consumption through price in the preceding analysis, we are in a position to explore the use of an arbitrary, exogenous level of demand in planning. Charging cost-based tariffs can seriously change the picture of capacity planning, since all components of demand growth - price-responsive demand, losses and theft, have the potential to decrease significantly. The next section explores an alternative approach to meeting demand reliably in rural areas from the demand side, rather than considering only supply options.

5.2.2 Supply Deficit or Excess Demand?

A recognition of the staggering amounts of capacity required in the next few decades to meet demand growth underlies the primary motivation of this thesis of commercializing a non-polluting technology for power generation. Chapter 1 discussed the sectoral breakdown of this growth, and pointed out the decreasing proportion of the agricultural sector in the share of demand growth due to rapid industrialization in the 90s. However, it was also found that significant irrigation potential exists throughout India, for which electric power remains the most popular and convenient source of energy. If increased urbanization of rural areas results from liberalization, the domestic and commercial demand in rural areas will also increase at a fast rate. Thus, there is no doubt that a large portion of capacity expansion must be slated for the development of rural areas.

However, this demand growth is significantly distorted by losses, profligate use of cheap energy and theft. The value of PVs increases with the relative level of demand, and therefore the perpetuation of the current inflated demand growth will significantly increase the value of PVs over time. *This indicates that the attractiveness of PVs are correlated with the presence of systemic failures in the power sector of rural areas. Solutions that target the heart of these failures, such as load management, actually work to decrease the value of PV in these applications.*

For convenience, the reasons why the attractiveness of PVs would decrease with the aggregate level of demand in rural areas have been reiterated below:

- Losses would decrease by the square of the decrease in load (capacity value of PVs will decrease);
- To the extent that the characteristics of Sonepat, Haryana represent the demand patterns of rural areas, a lower level of aggregate rural demand would lessen the peak demand of Haryana as a whole, thereby reducing the unit avoided cost of power (the avoided energy and capacity costs of PVs decrease);
- Lower aggregate demand would reduce the rate of distribution transformer failures and improve power factor, thereby reducing avoided T&D expenditure (the avoided T&D costs of PVs decrease).

Tariff reform has already been shown to be a necessary precondition for capacity expansion and for attributing any significant value to PVs. However, not only will cost-based tariffs allow SEBs to realistically plan power improvement in rural areas, they will also ameliorate the magnitude of the supply deficit by affecting demand. The introduction of a more rigorous tariff would curtail profligate consumption and losses directly, while the financial recuperation of the SEBs permitted by higher tariffs would potentially allow for better management and for the improvement of distribution equipment, thereby controlling pilferage.

The price-responsiveness of demand is very hard to determine a priori, thus it is very difficult to determine how much the value of PVs would decrease with tariff reform. The analysis of the previous chapter calculates the effect of loss reduction on the value of PVs. However, changes in consumption patterns depend on consumer preferences for available alternatives of electricity supply and the cost of electricity relative to other agricultural inputs. For example, if farmers prefer grid electricity to other available alternatives - usually diesel generators - only because of the price difference, demand may drastically reduce with a price increase. On the other hand, if electricity does not comprise a significant component of farmers' expenditure, they may not respond measurably, even if alternatives exist. Furthermore, unless prices are coupled with greater efficiency in monitoring of usage and revenue collection, the incentive for theft will increase.

Demand analysis clearly requires location-specific data and experience with the agricultural patterns of different regions. Nevertheless, the message here is that planning with a perspective focused strictly on supply can lead to band-aid solutions that ignore gross inefficiencies in the system. Planners need to move away from treating demand as an exogenous input. With the continuation of the status quo, the cost of power will increase, the supply deficit will increase, and the value of PVs will correspondingly reflect these changes.

6. Conclusions

The power sector of India faces tremendous challenges to keep up with demand growth. The liberalization of the Indian economy has opened the power sector to private and foreign participation in generation in order to meet the rapid pace of industrialization. At the rate planners expect to build capacity over the next couple of decades, there is a strong need to develop methodologies for capacity planning in order to ensure that the states' resources are utilized efficiently, to meet the needs of consumers within reasonable financial and technical constraints and to safeguard against the potentially catastrophic environmental consequences that a poor investment path could lead to. Motivated by these needs, this thesis discussed capacity expansion for rural areas with a high penetration of emission-free photovoltaic technology using an agricultural region of Haryana as a case study.

The most important conclusion of this thesis is that the solution to the supply deficit lies first in demand management, before any form of capacity expansion should be considered. This entails primarily a reform in agricultural tariffs in order to improve the financial viability of SEBs, thereby creating an incentive for power provision in rural areas. The current neglect of rural areas reflect a short-sightedness that is counterproductive to the objectives of improving agricultural productivity. Tariff reform would not only provide an economic incentive to build capacity, but would ameliorate the supply deficit by correcting distortions in demand and reducing losses. In the current state, the economic benefit of distributed generation lies only in the avoided energy costs. In a supply-constrained power sector, the actual avoided energy is not the most expensive to generate, and not nearly valuable enough to justify an expensive technology like photovoltaics.

Once an economic incentive to increase capacity is established, the penetration of distributed generation can realistically be evaluated. A production cost simulation of Haryana showed that the conditions encountered in agricultural Haryana are one of the most favorable areas for the deployment of PVs. It was found that a fairly high penetration level of up to 100 MW in the entire state is possible, even under the condition that PV systems are designed to cater to local demand Second. PV systems can achieve a capacity factor of 26%, with a range of ±6%, within a 98% confidence interval. Finally, with most of the new generation slated for private ownership and operation, the unit cost of power, and therefore the value of PVs, will increase in the future.

and operation, the unit cost of power, and therefore the value of PVs, will increase in the future. The uncertainty in solar insolation does not affect utility costs significantly - the value of PVs vary by 4% around their expected value. However, customers would bear a portion of the cost of poor PV performance in a given year, because of the corresponding decrease in reliability.

Technical and operational realities may lessen the theoretical potential of PVs. The likelihood of abnormal conditions and islanding would necessitate frequent disconnection of PV systems, which would reduce the effective capacity factor of PVs. The most plausible configuration and ownership structure of a PV system would be either to have privately owned plants, one on each distribution feeder, or multiple utility-owned panels installed located at the loads. The former would reduce losses more efficiently but require complicated and expensive protection and voltage regulation equipment. The latter would permit a concentration of protection equipment in one location, but the generated power would suffer line losses of its own, and therefore reduce the advantage of avoided losses. Either way, their net benefit is reduced.

PVs in Haryana appear economically attractive relative to other deployment scenarios. However, they are still far from being cost-competitive. In order to achieve sufficient price reductions, a worldwide demand of 600 MW in a period of five years is required. There are no signs today of such an impetus, and the market alone cannot generate this demand at today's prices.

The attractiveness of PVs are directly correlated with the presence of systemic failures in the power sector of rural areas. Inefficiencies in the distribution system in the form of high losses and frequent equipment failures significantly increase the value of PVs. The presence of losses render the capacity value of PVs very high. The value of PVs are also directly correlated to the aggregate level of demand. Solutions that target the heart of these failures, such as load management, actually work to decrease the value of PV in these applications. Hence, other alternatives that eliminate these inefficiencies of demand distortion and high losses need to be evaluated for their ability to meet rural demand more cost-effectively.

Power factor improvement is a virtually costless means of reducing losses, when one looks at the per unit cost of capacity generated, but it is by no means a sufficient alternative to capacity expansion. Even with close to perfect power factors, the value of PVs remain high, because losses remain high. This is because the distribution system consists of lengthy, low-voltage, overloaded feeders. The utility would have to upgrade the entire distribution system in order to reduce losses considerably.

The necessary condition of tariff reform to improve the financial viability of SEBs may go a long way in eliminating some of these inefficiencies along with reducing demand to the point that capacity expansion itself might not be necessary. For this reason, from the point of view of capacity planning in India, an emphasis has to be placed on demand management and tariff reform, rather than limit planning to supply. An exogenous use of demand in capacity planning, coupled with the current trends of privatization will only exacerbate the financial crunch of the SEBs and not improve the quality of power provision in agricultural areas.

7. Appendixes

Appendix 1. Solar Conversion Model

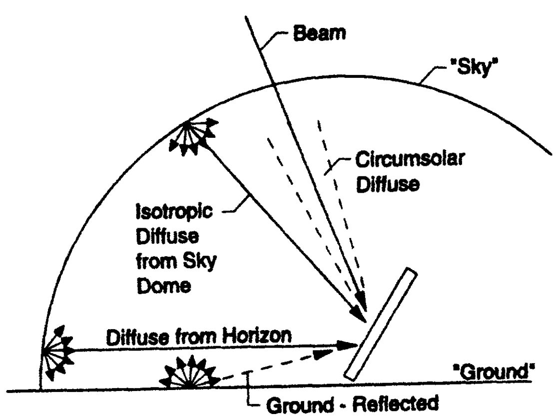
The conversion of solar energy to AC power fed to a grid requires the following steps:

1) Conversion of radiation on a horizontal surface to the total incident radiation on the surface of the solar panel, given the geometric orientation and characteristics of the solar panel;
2) Conversion from incident radiation to DC power output of the panels, based on the cell efficiency of the panels used;
3) Conversion through the power conditioning unit to AC power fed to the grid.

Only the first two steps were modeled in detail, while the third was just approximated as a conversion efficiency.

1) Anisotropic Diffuse Radiation Model [68]

The anisotropic model is slightly improved version of the isotropic diffuse model. In the isotropic model, the incident solar radiation consists of the (i) direct beam, (ii) diffuse radiation (iii) reflected radiation incident on the surface of the panel. The anisotropic model breaks the diffuse component components down further into isotropic diffuse, circumsolar and horizontal brightness components. The figure below illustrates the five different components of radiation. The only radiation data that these models require are the total and diffused radiation on a horizontal surface.



[68]Richard Perez et. al, Albany New York - Model description obtained from Beckman W. et al.

Total radiation on an incident surface:

$$I_T = I_h \cdot \sin\phi + I_d \cdot (1-F_1) \cdot \frac{1+\cos\beta}{2} + I_d \cdot F_1 \cdot \frac{a}{b} + I_d \cdot F_2 \cdot \sin\beta + I_d \cdot \mu_g \cdot \frac{1-\cos\beta}{2}$$

I_T = Total radiation incident on surface of panel

I_h = Direct radiation on a horizontal surface

I_d = Diffuse radiation on a horizontal surface

F_1, F_2 = Circumsolar and brightness coefficients, representing sky conditions, zenith angle, clearness and brightness.

a, b = Parameters that account for the angles of incidence of the cone of circumsolar radiation

μ_g = Ground albedo coefficient

ø = Incidence angle of beam on panel surface

ß = Tilt angle of panel

2) Radiation → DC Power Conversion: The cell degradation algorithm used was taken from the photovoltaic simulation tool, PVFORM[69]. For every °C above 25°C, a degradation of 4.33% in efficiency was assumed. For any temperature below 25°C, the efficiency was assumed to improve by 1%.

3) DC → AC Conversion: A power conditioning efficiency of .85, and another 15% loss in load-generation mismatch was assumed.

Therefore, the total AC Power output of the solar panel can be written as:

$$\text{AC Power} = I_T \cdot \mu \cdot .85 \cdot .85$$

μ = Cell Efficiency

[69]Written by Meniccuci, D., Sandia Laboratories

Data

The production cost model used to simulate the performance of photovoltaics in Chapter 3 required hourly energy output data. The solar insolation data used to generate this output was for New Delhi[70], which is less than 50 miles east of Sonepat, Haryana, and comprised the following parameters:

- Hourly (mean and standard deviation) total radiation on a horizontal surface ($KJ.m^{-2}$);
- Hourly mean diffuse radiation on a horizontal surface ($KJ.m^{-2}$);
- Hourly mean temperature (°C);
- Location Latitude (28° 58');
- Ground albedo coefficient (.1).

Table 7-1: Mean Global Hourly Radiation ($kWh.m^{-2}$) - New Delhi

Hour	Jan	Feb.	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	DEC
6	0	0	0.001	0.01	0.03	0.036	0.026	0.012	0.003	0	0	0
7	0.004	0.02	0.066	0.13	0.177	0.164	0.13	0.101	0.079	0.036	0.009	0.003
8	0.096	0.163	0.26	0.339	0.383	0.339	0.275	0.243	0.248	0.202	0.128	0.085
9	0.271	0.364	0.475	0.554	0.581	0.51	0.425	0.392	0.431	0.406	0.319	0.259
10	0.433	0.54	0.655	0.727	0.746	0.657	0.549	0.512	0.587	0.581	0.495	0.425
11	0.556	0.67	0.781	0.848	0.865	0.757	0.64	0.607	0.698	0.701	0.62	0.543
12	0.618	0.727	0.845	0.91	0.925	0.809	0.672	0.64	0.757	0.764	0.685	0.605
13	0.615	0.728	0.844	0.903	0.92	0.813	0.671	0.659	0.747	0.758	0.68	0.605
14	0.552	0.659	0.769	0.833	0.844	0.75	0.606	0.595	0.689	0.692	0.613	0.538
15	0.43	0.534	0.635	0.699	0.719	0.639	0.518	0.51	0.571	0.569	0.49	0.418
16	0.268	0.358	0.458	0.523	0.547	0.483	0.412	0.392	0.417	0.391	0.315	0.255
17	0.099	0.165	0.249	0.318	0.352	0.318	0.273	0.255	0.244	0.191	0.125	0.086
18	0.005	0.021	0.064	0.122	0.158	0.159	0.141	0.107	0.074	0.033	0.01	0.003
19	0	0	0.001	0.01	0.027	0.036	0.032	0.013	0.003	0	0	0

Mean Total: 1980 $kWh.m^{-2}$

[70] "Handbook of Solar Radiation - Data for India", Dept. of Science and Technology, Govt. of India, 1980

Table 7-2: Standard Deviation of Global Hourly Radiation (kWh.m^{-2}) - New Delhi

Hour	Jan	Feb.	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
6	0	0	0.002	0.008	0.012	0.015	0.016	0.01	0.005	0	0	0
7	0.003	0.012	0.029	0.038	0.045	0.056	0.066	0.054	0.034	0.016	0.006	0.005
8	0.033	0.055	0.065	0.071	0.075	0.1	0.128	0.123	0.085	0.048	0.034	0.026
9	0.073	0.092	0.093	0.093	0.096	0.138	0.175	0.183	0.136	0.075	0.061	0.058
10	0.104	0.124	0.114	0.111	0.116	0.164	0.217	0.237	0.179	0.093	0.076	0.085
11	0.125	0.132	0.135	0.119	0.113	0.18	0.241	0.269	0.197	0.11	0.086	0.104
12	0.135	0.15	0.141	0.13	0.113	0.183	0.26	0.282	0.205	0.109	0.087	0.109
13	0.137	0.152	0.139	0.137	0.113	0.169	0.266	0.275	0.212	0.118	0.087	0.104
14	0.122	0.143	0.145	0.13	0.134	0.171	0.258	0.261	0.195	0.112	0.086	0.098
15	0.104	0.121	0.125	0.123	0.127	0.16	0.228	0.231	0.174	0.093	0.072	0.081
16	0.078	0.092	0.1	0.111	0.116	0.142	0.184	0.18	0.143	0.075	0.057	0.053
17	0.033	0.055	0.072	0.077	0.09	0.104	0.128	0.124	0.093	0.049	0.032	0.023
18	0.005	0.015	0.029	0.039	0.054	0.058	0.067	0.058	0.034	0.017	0.007	0.003
19	0	0.002	0.003	0.007	0.014	0.018	0.018	0.011	0.004	0.001	0	0

Table 7-3: Mean Diffuse Hourly Radiation (kWh.m^{-2}) - New Delhi

Hour	Jan	Feb.	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
6	0	0	0.001	0.009	0.027	0.033	0.023	0.009	0.002	0	0	0
7	0.003	0.013	0.043	0.083	0.114	0.124	0.096	0.074	0.053	0.026	0.007	0.002
8	0.051	0.076	0.113	0.153	0.19	0.215	0.178	0.153	0.123	0.087	0.057	0.045
9	0.103	0.126	0.159	0.202	0.244	0.286	0.257	0.224	0.178	0.128	0.099	0.092
10	0.14	0.159	0.189	0.236	0.279	0.342	0.316	0.277	0.222	0.154	0.122	0.123
11	0.16	0.183	0.21	0.262	0.303	0.382	0.358	0.317	0.256	0.169	0.137	0.144
12	0.174	0.191	0.222	0.274	0.315	0.399	0.372	0.334	0.269	0.179	0.145	0.155
13	0.172	0.19	0.226	0.279	0.318	0.399	0.365	0.331	0.263	0.177	0.146	0.156
14	0.162	0.18	0.215	0.274	0.308	0.377	0.333	0.302	0.248	0.169	0.142	0.147
15	0.137	0.16	0.197	0.25	0.286	0.34	0.291	0.265	0.217	0.154	0.124	0.125
16	0.1	0.125	0.163	0.212	0.247	0.279	0.241	0.21	0.167	0.126	0.099	0.092
17	0.051	0.075	0.113	0.156	0.189	0.203	0.174	0.149	0.118	0.083	0.055	0.043

18	0.003	0.013	0.041	0.079	0.107	0.114	0.101	0.075	0.048	0.021	0.006	0.002
19	0	0	0.001	0.008	0.022	0.028	0.031	0.01	0.002	0.001	0	0

Mean Total: 770.5 $kWh.m^{-2}$

Table 7-4: Hourly Mean Temperature (°C) - New Delhi

Hour	Jan	Feb.	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec.
6	8.9	12.3	16.8	22.6	26.3	29.6	28.4	27.1	25.5	20.8	14.5	9.6
7	8.6	12	16.6	22.8	27.1	30	28.6	27.2	25.6	20.8	14.3	9.5
8	8.7	12.4	18	24.9	29.3	31.4	29.3	28	26.5	22.3	15.3	9.8
9	11	15.2	21.1	28.1	31.8	33.6	30.5	28.8	28.1	25.2	18.9	12.3
10	13.8	17.9	23.6	30.5	34.1	34.7	31.2	29.5	29.2	27	21.6	14.9
11	16.3	19.2	25.7	32.2	35.7	35.9	32	30.3	30.3	28.5	23.7	17.3
12	17	21.9	27.1	33.5	36.9	36.8	32.8	30.9	31.1	29.8	25.2	19
13	17.8	23	28	34.3	37.7	37.7	33.3	31.3	31.6	30.4	25.9	20.1
14	19.6	23.6	286	34.8	383.3	38.3	33.6	31.5	31.9	31.2	26.2	20.7
15	19.7	23.9	28.9	35.1	38.5	38.5	33.7	31.6	32	31.3	26.4	20.9
16	19.6	23.8	28.7	34.9	38.7	38.4	33.7	31.5	31.8	31.1	26	20.7
17	19.1	23.4	28.4	34.7	38	38.2	33.4	31.4	31.5	30.6	25.2	19.7
18	17.2	22	27.2	33.7	37.5	37.7	33	31	30.7	29	22.9	17.2
19	15.5	20	25.3	31.9	35.9	36.7	32.4	30.3	29.5	2.7.2	20.9	15.9

Photovoltaic Panel Assumptions

• Fixed plate solar panels

Tilt (β) = 30° (approximately the location's latitude of 28' 58'')

• Thin film technology

Cell Efficiency (μ) = 10% at STC[71].

[71] Standard Test Conditions - 25°C, one Atmospheric pressure

Appendix 2. LOLP Calculation with Intermittents

The following methodology presents the analytically exact form of the LOLP in a capacity plan with intermittents, for the purpose of calculating the ELCC of the intermittents, and eventually their capacity value. This builds on a conventional LOLP calculation presented by Henry Kelly in [Johansson et al. 1993]. It requires a normal distribution of the energy output of the intermittent for every hour of the year. See Section 4.8.2 for a discussion of the results obtained for photovoltaics.

For a dispatchable set of plants, an LOLP results from the forced outage rates of power plants. For the jth plant type consisting of N_j plants with a forced outage rate of Fo_j, the probability that n of them are unavailable in any hour is given by:

$$P(n_j) = \frac{N_j!}{n!(N_j - n)!} Fo^n (1 - Fo)^{N_j - n} \qquad n = 1, 2, \ldots N_j \qquad \text{(A.1)}$$

The probability that M_j megawatts of capacity are available from these plants can be found by substituting $\frac{M_j}{c_j}$ for n in the above equation, for a plant size of c_j megawatts.

The distribution of different plant types can be convolved to give a cumulative probability distribution for the loss of load probability per hour. In order to incorporate the intermittent generation, this distribution needs to be convolved with the hourly Gaussian distribution of the intermittent. The Gaussian can be discretized in the following manner with an arbitrary level of accuracy in order to perform the convolution.

Given the two Gaussian parameters E_i and σ_i and an interval size of k_i megawatts:

Approximate the area under the Gaussian within each interval to that of a parallelogram to get the probability that I megawatts of intermittent output are available:

$$P(I_i) = k \frac{1}{2\pi\sigma_i} \; e^{\frac{(E_i - I_i)^2}{2\sigma_i^2}} \qquad \text{(A.2)}$$

The probability distribution for the total available capacity can be found by convolving the individual distributions in A.1 and A.2 (using * for convolution):

$$P(M) = P(n_1) * P(n_2) \ldots * P(n_j) * P(I_1) * \ldots P(I_i)$$

The loss of load probability in an hour t with a load of M megawatts is:

$$P(\leq M_t) = \sum_{n=1}^{M_t - 1} P(n)$$

The LOLP for the system is then:

$$LOLP = \sum_{t=1}^{8760} P(\leq M_t)$$

Appendix 3. Financial Calculations

The following calculations form the basis for the results obtained in Chapter 4. They have been adopted from Johansson et.al (1993). The software SUTIL used in the analysis also use these financial assumptions.

Capital Cost

The utility discount rate referenced in Section 4.5.3 is the weighted cost of capital:

$$d = rb.fb + re.fe$$

re: rate of return on equity | fe: fraction of investment financed with equity

rb: rate of return on bonds | fb: fraction of investment financed with bonds

The fixed cost rate assumes that a sinking fund is used to accumulate capital for repayment at the end of the plant's life. In the absence of taxes, the fixed cost rate is:

$$FIX = IN + CRF(L,d)$$

Where IN is the insurance rate, and CRF(L,d) is the capital recovery factor for an annuity of period L paying interest d.

$$CRF(L,d) = \sum_{L} \frac{1}{(1+d)^{L}}$$

The annualized capital cost of a plant, for an overnight cost, including fixed O&M, of $ (C+FOM)/kW is:

$$CA = FIX . (C+FOM)$$

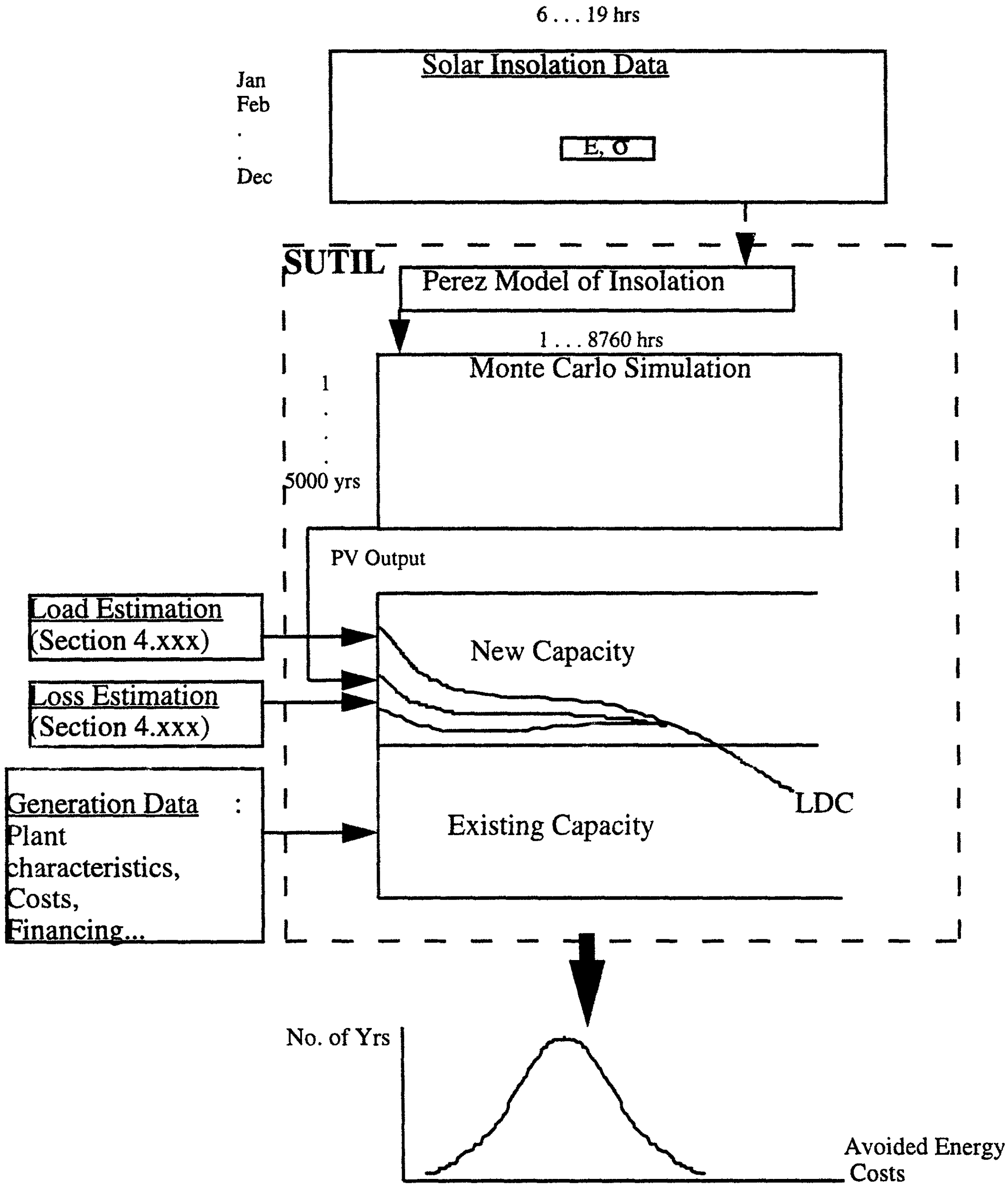
Fuel Cost

The levelized cost of fuel for a fuel price of F(t) in year t is computed similarly as:

$$FP = \sum_{t=0}^{L} \frac{F(t)}{(1+d)^{t}}$$

Appendix 4. Illustration of Methodology Implementation

The diagram below illustrates how the components of the new production cost model described in Chapter 4 fit together in the final implementation using the software SUTIL.



Appendix 5. Optimal Location and Sizing of PV Systems

This section applies results of research conducted by Grainger and Lee (1981) on the optimal siting of shunt capacitors on distribution feeders to the configuration of PV systems in order to minimize losses. The implications of these conclusions for ownership and feasibility of deployment are discussed in Section 5.1.1.

<u>Assumptions</u>

1) The optimal siting of PV panels is a dynamic programming problem, since the objective - minimizing losses - is a function of a probabilistic input - solar insolation. If one simplifies the problem to one of a deterministic nature, where power injections of PV panels are assumed to be the mean of their respective probability distributions, the optimal siting of PV panels reduces to an analytically identical problem as that of siting capacitors. In the former a purely reactive injection of power (capacitor) compensates reactive load along a feeder, while in the latter case an injection of real power reduces loading at the substation. Both contribute identically to iosses and power.

2) The application of results directly from the one to the other additionally requires the assumption that PV panels do not inject or demand reactive power - in other words, they operate at a power factor of unity. This would require that the inverters used be self-commutated. It should be noted that this is not the most economic choice. Line commutated inverters are much cheaper, but they draw significant reactive power from the grid. However, since this only exacerbates the problem addressed, and since most inverters manufactured today are forced commutated, this assumption is reasonable.

Optimization Parameters

Loss minimization typically has two objectives:

i) Peak power reduction (L_p); ii) energy loss reduction (L_e).

The final objective is to minimize the cost of losses, hence the objective can be written as:

$C_{sav} = K_e L_E + K_p L_p$

Where K_e and K_p are weighting cost functions that may represent the relative importance of the saved T&D costs peak power reductions against energy loss savings.

Three degrees of freedom exist for the optimal deployment of PVs to minimize losses:
i) Number of PV panels; ii) Location of panels along the feeder; iii) The size of each panel.

Take a feeder of uniform resistance r and length l with a load distribution I(x). For n PV panels located at distance x_i from the substation with current injections PV_i each, the peak power loss reduction is given by: [72]

$$L_P = 3\{\int_0^l I^2(x)rdx - [\int_0^{x_n}(I(x)-\sum_{j=1}^{n}PV_j)^2rdx + \sum_{i=1}^{n-1}\int_{x_{i+1}}^{x_i}(I(x)-\sum_{j=1}^{i}PV_j)^2rdx + \int_{x_1}^{l}I^2(x)rdx\,]\}$$

$$L_e = \int_0^T L_p\,dt, \qquad \text{or} \qquad L_e = L_p.8760.L_f$$

Where L_f represents a loss factor. Two observations are evident:

1) Losses are a non-linear function of the three parameters, and therefore a closed-form solution to the optimization problem cannot be obtained easily.

2) The greater the number of PV panels, the greater the loss reduction, assuming optimal siting of the panels.

i) <u>Number of PV panels</u>

Most often, the optimal location and size are calculated based on a given number of capacitors. For a discrete load distribution, the number of PV systems should equal the number of loads to minimize losses. The economic benefit, however, may not be maximized, since more panels require more equipment to connect to the grid (e.g., protection equipment, inverters). The optimal number can be calculated iteratively, given costs of the necessary equipment. Two cases are considered here, based on the two forms of ownership and management discussed in Section 5.1.2.

a) One PV plant per feeder

b) n PV panels, where n is iteratively determined using a modified cost function:

$$C_{sav} = K_eL_E + K_p\,L_p - \sum_n K_{pv}$$

ii) <u>Location and Size</u>

---

72 Grainger and Lee, "Optimum Size and Location of Shunt Capacitors for Reduction of Losses on Distribution Feeders", Pg. 1107

If feeders are assumed to have uniform resistance and be uniformly loaded, in order to maintain consistency with the calculation of losses, some simple rule-of-thumb relations can be used to locate PV systems.

a) For one PV plant, the optimal location is at a point two-thirds down the feeder *provided* the capacity of the plant is designed to be:[73]

$$I_{pv} = \frac{2}{3}\frac{A}{B} I_{max} \qquad A = K_e L_f T + K_p \qquad B = K_e T + K_p$$

Where L_f is the load factor of the feeder, I_{max} is the peak current, and T is the time interval over which energy loss is being minimized.

b) For n PV panels, the 2/2n+1 rule can be used:

$$I_{pv} = \frac{2}{2n+1}\frac{A}{B} I_{max} \qquad x_i = \frac{2i}{2n+1}\frac{A}{B}$$

Discussion

An important observation pointed out by Grainger and Lee is that an incorrect assumption of uniform load distribution can not only reduce savings, but potentially increase losses.[74] An optimal configuration requires knowledge of every load on a feeder. Such level of detail rarely exists. Nevertheless, in the face of limited data, one can always ensure the reduction of losses at the cost of a sub-optimal configuration. However, the important point is that the more knowledge one has of the load distribution, the more valuable PV systems will be.

[73] Schmill, J, "Optimum Size and Location of Shunt Capacitors on Distribution Feeders", Pg.826

[74] Grainger and Lee, "Optimum Placement of Fixed and Switched Capacitors on Primary Distribution Feeders", Pg. 345

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