A METHODOLOGY TO ASSESS THE INTERACTIONS OF RENEWABLE ENERGY SYSTEMS DYNAMICS WITH FLUCTUATING LOADS

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(Abstract)

This dissertation introduces a new planning and operational tool to integrate photovoltaic (PV) systems into the utility's generation mix. It is recognized that much of the existing research concentrated on the central PV system, its operations, and long-term planning with PV system and concluded that technical problems in PV operation will override any value or credit that can be earned by a PV system and that existing breakeven capital costs make large-scale PV penetration limited. First of all, in most cases, PV power was subtracted from the utility load with the expectation that conventional generation would meet the load. This approach is valid for small penetration levels and for PV facilities connected near the load centers. Second, PV system was studied on a case-by-case basis. This made the interactions between the PV systems and conventional power systems not well known to the operator in the dispatch center on one hand, and to the PV system manufacturer, on the other hand. In addition, several constraints such as thermal generation ramping capabilities, energy costs, tie-line interchange, spinning reserve requirements, hydro availability and generating capacity, and pumped-storage

scheduling are not adequately represented in this process. These are real problems and their solutions are sought in this dissertation. Finally, the value of PV systems does not lie only in serving load, but also in reducing problems associated with emissions. It is felt that a comprehensive methodology that would take into account the PV system characteristics and the forth mentioned constraints, as well as more global penetration is developed. The proposed methodology is designed to handle load dynamics and PV fluctuations, so as to minimize operational problems.

The objective of this study is to determine the economic and operational impacts when large photovoltaic systems are incorporated into the electric utility generation mix. The proposed methodology handles combustion turbines, hydro and pumped-storage hydro power systems. Performance analysis shows that hydro availability, generation mix and characteristics, PV power output dynamics and performance, time of the year, and energy costs influence the economic and operational impacts of large-scale PV generation. Results show that while hydro dispatching increases acceptable PV penetration levels, generation mix and energy costs influence the breakeven capital cost. According to this study, for a 10 percent PV penetration level (1200 MW) and high energy costs, the breakeven capital cost is \$968/kW and \$1200/kW for Richmond (Virginia) and Raleigh (North Carolina), respectively. This corresponds to an energy cost of 3.20 and 3.00 ¢/kWh for Richmond and Raleigh.

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I dedicate this dissertation to my brother Jamel.

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CHAPTER 1.

INTRODUCTION

As the price of electricity has risen, interest in renewable energy sources, wind energy conversion systems (WECS) and photovoltaics (PV), in particular has increased. With high penetration of PV and WECS, operation problems are bound to exist. Therefore, proper operation procedures are required. These procedures include unit commitment, regulation, economic dispatch, and automatic generation control. The use of such procedures would provide sufficient system security and alleviate operating problems caused by PV and WECS power output variations. In particular, the two serious operating problems that occur during significant weather changes that sweep PV and WECS facilities are: first, the automatic generation control would saturate if their instantaneous generation and load fluctuations would exceed the load following capability of the system. Second, the generating units under governor frequency regulation could repeatedly cycle if wind and PV generation dynamics cause frequency durations that exceed governor deadband. Meanwhile, it is anticipated that PV and WECS would be installed in a distributed fashion. That is, several PV and WECS facilities are scattered over the entire service area of the utility, covering hundreds of square miles. It is expected that as weather conditions vary from one site to another, PV and WECS diversification would reduce the severity of the operation problems forth-mentioned.

High capital cost of conventional generating capacity, increasing environmental concerns, small or otherwise uncertain load growth, increasing interest in modular and low risk capacity additions, and regulatory requirements have lead electric utilities to study large scale integration of renewable energy sources (RES) into their existing power systems. Because of their intermittent and unpredictable nature, RES can pose operational concerns. The major problems associated with these sources are related to distribution and transmission, automatic generation control, transient instability, spinning reserves, and frequency excursions. Therefore, it is in the interest of the utility and third party to utilize new operational tools to reduce the impacts of these problems on the cost of energy and service quality. Moreover, existing dispatching techniques are capable of handling renewable energy sources on a case by case basis. Whether these systems are operated in stand-alone, dispersed, or hybrid mode, their power output has generally been treated as a negative load with the expectation that the electric utility will meet the residual load with conventional generation. This is probably true when the penetration of RES into the grid is small. With the expected increase of penetration of RES into the grid, the treatment of such systems as a negative load may not be adequate. Moreover, when their penetration increases, it will most likely be in a distributed fashion. Thus, it is important to study the fluctuations of their output.

The Public Utilities Regulatory Policies Act (PURPA) was one of the principal components of the National Energy Act passed by Congress in 1978. Sections 201 and 210 were designed to encourage the promotion and development of alternative electric generation and conservation technologies. Among the many issues addressed by PURPA are the issues of marginal cost pricing of electricity and demand side conservation measures. The two primary goals set in the PURPA mandate are the promotion of renewable energy resources and technologies and energy conservation. It is now in the interest of the electric utility and small power producers to examine and improve the use of renewable energy sources. Certain goals need to be satisfied such as reducing capital cost, improving solar conversion efficiency, improving and standardizing integration of renewable energy sources.

A considerable amount of work has been done in the solar conversion industry and electric utility generation expansion planning and dispatching techniques to integrate photovoltaics and wind energy systems into the electric grid. For the generation expansion planning purposes, average performance indices are used to study the long term impact of RES on generation, distribution and transmission, production cost, and reliability. However, for short term operations, static and steady performance indices are assumed. Moreover, in both cases, operating and maintenance costs have not been accounted for.

While existing unit commitment and economic dispatch techniques function well, they are not capable of taking into account the variable costs and dynamics of PV systems as well as the load variations. The result is that the larger opportunity of benefiting from the diversity of RES generation and load is lost and that adverse problems are not detected. In addition, existing literature indicates that developed techniques ignore operating and maintenance costs for both generation expansion planning and short term production cost. O&M costs can be ignored only for small PV systems. With the high capital, operating, and maintenance costs, the optimum solution for unit commitment and economic dispatch would not be reached and the recommendations would be inaccurate.

Here, the use of recent advances in RES technology, increase in programming capability and rigorous operational modeling is proposed so that short term cost benefits, system reliability and stability are improved. In addition, the proposed methodology can be used for different renewable energy systems with minimum modifications.

RES power output depends on weather conditions and technology. Frequent weather changes can translate into extremely high variations in their output. This would cause operational problems such as load following, frequency excursions, spinning reserves requirements, and system stability. Moreover, system load variations may reach 0.2-0.4% of the peak load per minute. However, conventional generation response capabilities are limited except for combustion turbines and hydroelectric power plants. Existing operating tools have addressed some of these issues but without renewable energy systems. Other studies incorporate these systems, but do not account for their variations. The underlying assumption is that for insignificant penetration levels, output fluctuations can be ignored. For high penetration levels, the interactions of these fluctuations with the load can be significant and could cause severe operational problems, making generation control a difficult task.

It should, however, be realized that the highest benefits of using RES are possible when their capital and operating costs are low, their adverse effects are minimized, and their capacity factors are maximized. The implementation of the proposed methodology would help in quantifying these benefits.

The proposed technique presents a comprehensive approach for dispatching PV in particular, and non-conventional energy sources, in general. Combustion turbines and hydro power plants are found to enhance, to a large extent, the economic and operational value of large scale PV applications. Generating unit ramping rates and daily hydro availability constraints play a major role in this matter. The model is tested using a synthetic PV generation system consisting of three sites in Virginia and North Carolina. These sites are the Virginia Tech Solar Test Facility (VTSTF) in Blacksburg, the Virginia Integrated Solar Test Arrays (VISTA) operated by Virginia Power near Richmond, and the Solar Test Facility operated by Carolina Power and Light Company near Raleigh. Actual PV output measurements from these sites are used in the synthetic PV generation system.

The present work includes a brief review of existing dispatching techniques with PV power systems, and a description of the proposed technique. The technique is implemented for a typical US electric utility using actual load and PV output data.

CHAPTER 2.

PROBLEM STATEMENT

The growing interest in photovoltaic and wind energy conversion systems has become evident as several utilities are considering generation planning with renewable energy systems. Whether these plants are built by the utility or a third party, the utility needs to optimally utilize their energy. Several crucial factors exist as the penetration level of PV increases. It is expected that PV systems would comprise of several facilities spread over several hundred miles whose output level is as predictable as the weather conditions and changes with the weather. For instance, a moving cloud could reduce the output from a full capacity to zero or vice versa in few minutes. Moreover, thermal generation and transmission system may not be able to absorb these fluctuations. Finally, load management and control activities may not be able to adjust the load level accordingly. In light of these simultaneous dynamics, unit commitment and economic dispatch techniques that require more precise load, generation, distribution and energy management models are needed. The purpose of this dissertation is first to put together these models and second to develop a methodology to validate these models through simulation.

The intent of this research is to investigate the necessary measures to cope with the RES dynamics and operating costs and load variations and with the limited response rates of conventional generation. This is done by first finding the economical and operation model for the renewable energy systems, second by developing a 24-hour updated unit commitment that would include load and RES power output forecast, third by developing a short-time economic dispatch algorithm that runs every few minutes. Finally, these models are validated through simulation involving typical US electric utilities and recent advances in renewable energy technologies. Several PV production cost models are obtained using data from existing large scale PV systems. The updated unit commitment and economic dispatch are based on existing analytical and programming tools and would account for constraints imposed by the PV generation, load variations, and response rates of conventional generation. A 24-hour load forecast and RES performance forecast are obtained using forecasting techniques developed at the Energy Systems Research Laboratory at Virginia Tech. It is anticipated that a major impact on energy value of the PV generation will be in the short-time fluctuations. Consequently, a short time step, preferably 10 minutes or less would be utilized. The seasonal variations of solar resources and utility load and generation will be accounted for.

In this dissertation, the economic impact on energy cost of incorporating large PV systems into the electrical generation mixes of various utilities is studied. The characteristics of the utility generation mix which would enhance the value of PV energy are identified for this purpose. Furthermore, the methodology should be generic enough to handle other renewable energy systems with a minimum amount of modifications.

2.1 Need for Analytical Tools

The negative load concept applied to PV and wind energy systems integration stems from recent but limited experience with these sources of energy. In fact, central station PV and wind turbines are still in the experimental phase. Only few megawatts are now commercially used, most of which are used in remote locations where they directly serve a portion of the load. In addition, renewable energy resource based industries and utilities are not yet engaged in large scale production and purchase. Coupled with this, electric utilities still risk high capital costs that would be required by multi-megawatt PV and wind facilities. These factors have created a limited experience with integration and operation of renewable energy sources. Neither operating and economical models have been obtained. It is anticipated that providing such models would help to identify the potential of using these alternate energy systems for producing bulk power. In this dissertation, such models are investigated as a first stage. In the second stage, these models are validated through simulation in which several electric utilities are considered. Key operating and economical parameters will be taken into account. In addition, the following indices need to be investigated in determining PV generation value:

- Capital cost,
- Response rates of PV system as a function of time, space, dispatching time interval, and system load,
- Operating strategy,
- Energy Costs,
- Spinning reserves contributions,
- Area control error, i.e. the countermeasures that automatic generation control would take into account for the intermittent PV performance,
- Operating and maintenance costs,
- Diversification of PV generation,
- PV Power output dynamics,
- PV power output seasonal variations,
- Conventional generation mix, and
- Load variations.

Quantifying such indices will define not only the proper operating strategy of PV systems, but also the merits of using solar energy for bulk power generation.

2.2 Issues Addressed

It is evident that the forth-mentioned indices are essential, thereby, need to be considered in the short term production cost methodology. The following tasks need to be accomplished. These are developing a new unit commitment and dynamic economic dispatch, and devising a new automatic generation control.

- Operating and maintenance (O&M) costs reflect fixed and fuel related costs. Essential components of PV O&M costs are investigated in this study.
- Unit commitment is the process of selecting a combination of generating units that will supply the expected 24 hour load of the system at the least cost and provide adequate spinning reserves. How pumped-storage and hydro dispatching can influence the unit commitment solution needs to be discussed.
- Economic dispatch is the procedure for the distribution of total thermal generation requirements among the various energy sources for the optimal system economy. It takes into consideration generating costs, transmission losses, responses rates, fuel costs and availability, and capacity (lower and upper) bounds.
- Automatic generation control's main function is to track the load variations while maintaining system frequency, net line interchanges, and optimal generation levels as determined by the unit commitment and economic dispatch.

While unit commitment, economic dispatch and automatic generation control exist, they can handle PV and wind systems in a static mode. With the increasing experience with these non-conventional energy systems, new short-term operation techniques are needed to account for their power output fluctuations as well as load variations.

In particular, this study was designed to answer the following questions.

1. What are the major factors in utility generation mix which influence the value of PV energy?

2. What are the typical ranges (in $/kWh) of PV energy value to an electric utility,

3. Can any conclusions be drawn on a possible upper limit to the value of PV under a specific utility scenario?

4. What is the significance of tie-line interchange, pumped-storage scheduling, hydro availability, energy costs, and generation mix on the PV penetration level? and

5. What is the breakeven cost ($/kW) of large scale PV penetration?

This dissertation is divided into the following parts: (i) Literature Review of Renewable Energy Systems and advances in Unit Commitment and Economic Dispatch, (ii) PV System Performance, (iii) Weekly Pumped-Storage Hydro Scheduling and Constrained Hydro-Thermal Unit Commitment, (iv) System Operation with PV Systems, (v) Case Studies (vi), Breakeven Capital Cost Assessment, (vii) Conclusions and Recommendations, (viii) References, and (ix) Appendices.

Chapter 3 establishes the context of the research giving accounts of background literature. The first area covers recent advances in renewable generation technologies, utility experience with multi megawatt PV systems, and performance (energy production, operating and maintenance costs, reliability). The second area presents recent advances in unit commitment and economic dispatch.

Chapter 4 addresses PV system performance and requirements. Two inter-dependent areas are covered. First, single and distributed PV system performances are compared. Mixed technology PV system performance is also discussed. Second, reactive power requirements for operating PV systems are also analyzed.

The development of the proposed short-term planning and system operation methodology is given in Chapters 5 and 6. Chapter 6 starts with the hierarchical relationship between long-term and short-term planning and system operation. Next, the weekly hydro-thermal scheduling is developed. The interactions between PV systems and pumped-storage scheduling are discussed. Then a 24-hour unit commitment with contained hydro is developed. Implementation of both models is also included.

In Chapter 7, system operation with photovoltaics is discussed. Operation requirements and generation control are addressed. The economic dispatch solution is proposed. Hydro dispatching is also discussed. This is followed by identifying the requirements of automatic generation control with PV systems. Case studies are performed reflecting various assumptions and control options.

In Chapter 8, the implications of system characteristics, PV system performance, and scheduling options on the PV energy value and breakeven capital costs are discussed.

Conclusions and recommendations are the subject of Chapter 9. In Chapter 10, references are included.

CHAPTER 3.

LITERATURE REVIEW

An extensive literature search has been conducted in the areas of renewable energy source operation and performance, unit commitment, economic dispatch, and automatic generation control. The need for this discussion stems from the nature of the proposed solution. The presentation in this chapter deals with advances in PV and wind energy systems and their integration into the electric utility grid. This includes state-of-the art in PV and wind energy system technology, prospects, operation modes of PV systems, and large-scale PV systems dispatching.

3.1 State-Of-The Art in PV and Wind Energy Systems

There is evidence that electric utilities are looking into the future and believe that central station PV and wind energy systems have real potential. However, at this time, utilities are still concerned about the problems related to solar and wind technologies. These are economics and operating characteristics. The reader shall bear in mind that while this discussion would focus on PV systems, wind and solar thermal power plants would be brought up for comparison purpose.

Large-scale PV and wind systems are already installed or planned for construction. Most of them are small-scale systems and are connected to several electric utilities. In fact, 849 MW of photovoltaic and 1800 MW of wind capacity are operating or planned for construction [125]. Today's costs of solar PV systems are over $10,000/kW, and the R&D goal for solar PV is to bring the capital cost down to $3,000/kW. Recent large PV projects and design studies indicate high installed capital costs as shown in Table 3.1. Table 3.1 shows the capital cost reductions from 1981 to 1984, 1989, and 1991. Capital cost reduction is due in part to increase in system size and improve in solar cell efficiency. A study by Herig and Atmaram [48] indicates that the installed capital cost for the Florida Power Corporation 15-kW PV system is $13,900/kW and that total labor costs represent 25% of the total project cost. The Photovoltaics for Utility Scale Applications (PVUSA) Project is setup in two phases. In phase 1, the project is fielding a dozen different PV technologies. Their total capacity is about 1 MW peak ac output. The largest is a 400 kW system, was completed in 1991 under $5000/kW. Phase 2 will be completed and evaluated between 1992 and 1995. No cost data are available at this time. Similarly, Leonard [71] suggests that photovoltaic systems would be economically competitive with other generating technologies if the installed capital cost were in the $2,000 to 4,000/kW range. That is, the module and array prices would range between $1,000 and $2,000/kW.

In several studies, break-even capital costs were investigated for different solar technologies, penetration levels, energy storage options, and generation mix. The results are mixed, nevertheless, they indicate low break-even capital costs. Ku et al. [67] estimated that the break-even capital cost for PV plants ranges from $1100 to $1350/kW in 1982 dollars for 15% and 2% penetration levels. According to a study by Krawiec [65], the break-even capital cost ranges from $400 to $770/kW for 500-MW and 100-MW systems. A Study by Shushnar et al. [102] indicates that the balance of systems costs are sensitive to the PV efficiency, system configuration, and equipment design. The authors reported that for 15% solar cell efficiency at an area related cost of $600/m^2, the capital cost is $3720/kW.

Patapoff and Mattijetz [78] reported that utility experience to date with photovoltaic systems has been with small dispersed systems designed primarily as demonstration projects. The 1-MW photovoltaic plant at Lugo Substation in Hesperia, California, has been designed and is operated as a central station power plant. The performance of the system has been monitored since first coming on line in November 1982. The potential impact of this similar system upon the operation of the utility is discussed.

The grid-connected photovoltaic facility of Switzerland has been in operation since December 1989 [124]. In 1990, it produced electricity at a cost of $0.78/kWh. In 1990, the PV plant has been in operation for 75 percent of the time and supplied 85 MWh to the grid. The yield for 100 percent operation is about 111 MWh. The annual average efficiency of the system reached 7.9 percent, while that of the inverter was 95.9 percent. It is expected that further installations should cut energy cost by 50 percent before the year 2000.

Ku et al. [67] presented a methodology and results of studying assessment of the economic viability of long-term applications of PV generations in a large eastern electric utility. The results indicate that with respect to a conventional generation alternative, such as combustion turbines, the break-even capital cost for PV power plants ranges from $1100/kW and $1350/kW, in 1982 dollars, for 15% and 2% penetration levels and that this break-even cost decreases as the penetration level increases. In this study, the PV power output is subtracted from the total load and the chosen time resolution is 2 hours.

These and other studies show that greater potentials for PV depend on improving solar conversion efficiency, reducing balance-of-system costs, and maximizing energy delivered to the utility. Economical analysis and simulation studies agree that a capital cost of $1,000/kW or less would make central station PV economically acceptable and competitive with conventional generation.

3.2 Operating, Maintenance and Production Costs

Several studies involve setting up guidelines for how much and at what cost electricity from PV is produced. For stand-alone and dedicated applications, the cost of energy is not critical. For grid-connected applications, competition with conventional generation exists and the cost of electricity becomes a decision issue.

Based on a study by Sørenson [130], the average busbar cost of electricity from wind turbines is 1.8 ¢/kWh and 2.3 ¢/kWh with and without storage, respectively. The energy cost for nuclear plant is 2.6 ¢/kWh assuming a $700/kW capital cost. Marier [74] reported that the levelized cost of electricity ranges from $0.50 to $1.00/kWh for photovoltaic and from $0.06 to $0.11/kWh for wind energy systems. While for oil, the levelized cost ranges from $0.17 to $0.30/kWh. Marier reports that the wind energy operation costs are the cheapest with the exception of hydro. Evidently both high capital cost and low energy production from PV systems are the sole reasons for the high cost of electricity produced by PV systems. Studies by EPRI [36] reported that O&M costs for central-station PV are estimated between 0.19 and 4.7 ¢/kWh. The actual O&M costs are reported to be much higher depending on the PV system size and design. Tables 3.2 through 3.4 list actual O&M costs for several PV facilities, in the US and Europe.

According to Tables 3.2 through 3.4, the O&M costs for a given facility depend on the PV system size and tracking mode. The 27-kW PV power plant installed in Dallas Ft., Texas has the highest operating and maintenance costs. These tables indicate also that the total operating costs of wind and PV systems will decrease relative to fossil fuel technologies as conventional fuel costs tend to increase through the end of the century. In fact, Stranix and Firester [107] recognized the heavy impact of increasing fuel costs on the price of energy, a matter that would enhance the economic viability of wind and PV systems. For example, the total annual O&M costs for a 50-MW PV plant would be \$4.82/kW. Those for a typical 50-MW conventional power plants are \$15/kW plus a 0.3 ¢/kWh variable cost. Considering the large difference in fuel costs, maintenance and operation requirements, the O&M costs for a PV facility represent a small fraction of those of a conventional power plant. Similarly, Chernick [19] quantified the economic benefits of risk reduction due to PV solar installation. It is reported that as solar PV offers smaller increments of capacity expansion, lower risk in capital expenditures, project cancellations, and fuel costs' variations is reduced. The author encourages utilities to consider low-risk solar energy supplies even at the expense of high capital costs.

Conover [28] discussed the results of several PV projects and presented actual O&M costs experienced by seven selected PV installations in the United States. The report includes the documentation of the largest problems areas, identification of failure causes, and projections of O&M costs for future installations.

Schaefer [97] reviewed the performance, availability, and maintenance for 10 photovoltaic plants in the US since 1983. Problems were examined and achievable capacity factors were formulated and presented. The cost of photovoltaic electricity was developed as a function of investment cost, maintenance costs, and capacity factor which in turn depended upon the site, the plant's availability and tracking systems. It is expected that as maintenance costs would decrease for new PV plants. The O&M costs would not exceed the 0.5 ¢/kWh level.

Sørensen [130] recognized the market potential of wind power systems, in particular if they are backed up by storage facility. Wind power plant is reported to have an O&M cost of 0.3 ¢/kWh, which is higher than that for oil plants, but much lower than that for nuclear power plants. In addition, the capital cost for wind systems is much lower than that for nuclear power plants. This meant lower busbar cost of electricity for wind energy system than f or oil-fired and nuclear power plants. It is estimated that the wind busbar cost is 1.8 ¢/kWh and 1.3 ¢/kWh with and without storage, respectively.

From this short review, it becomes evident that considering PV and wind as power generation alternatives still receives mixed reaction from both the utility and the customer. However, lower capital cost would be possible if both the electric utilities and the solar and wind energy systems industry would cooperate to build more large scale systems. This would in turn increase operating experience, improve system design, and reduce overall O&M costs.

Estimates of potential O&M costs for future installations show that these costs will not significantly affect the overall cost of energy from photovoltaic systems. Additional reductions in O&M costs can be achieved most effectively through research concentrated on increasing the reliability of power conditioning and tracking devices.

3.3 Prospects of PV Systems

There is no doubt that the world is facing two serious problems regarding energy. The first is the continued depletion of fossil fuel reserves. Conservative estimates conclude that fossil fuel reserves could be depleted within two centuries. The second problem is the dramatic increase in global pollution. The world-wide pollution damages could exceed $1700 billion a year. In the face of these problems, solar energy seems to be the most appropriate source of clean energy. Researchers and PV manufacturers expect to develop PV systems with 20 percent efficiency. The cost of solar energy would drop from $0.30/kWh in 1990 to $0.02/kWh in the year 2030. Solar energy's potential in the future will depend on its ability to overcome major barriers. These include low fuel costs, reduced Energy Tax Credit, lack of recognition in term of pollution reduction and economical benefits, and lack on incentive for investment in renewable energy sources. Accounting for social and environmental costs, wind and solar energy becomes very attractive in comparison to conventional generation. Table 3.5 lists cost of generation from different sources. With continuously increasing operating experience with wind and PV systems and improving system design, energy costs would drop drastically.

Shugar [132] presented results of work undertaken at Pacific Gas and Electric to quantify the potential benefits of distributed grid-connected photovoltaic generation. The author indicates there would be significant distributed benefits in carefully chosen transmission and distribution systems. Among the benefits due to PV integration are first, the system energy value, defined as the avoided energy cost is estimated to be \$194/kW/year. Second, the generating capacity value is calculated from the avoided cost of using a peaking gas turbine and is estimated at \$65/kW/year. Third, the transmission capacity reflects the avoided transmission cost and generation cost value. The transmission capacity value is estimated at \$42/kW/year. Fourth, the reactive power value is the result of voltage support to transmission and distribution system. The levelized annual value of reactive power loss savings is estimated at \$67/kW/year. Finally, the annual distributed benefits are approximately \$720 per kW. These benefits could enable PV generation to be a potentially cost-effective alternative for utility planning, and thereby simulate utility demand for PV systems.

Shushnar et al. [102] reported a cost study of a 5-MW PV power plant. In this study, various configurations are considered using actual data and experience from ARCO solar large scale PV projects in California. The study indicates that PV and area related balance of systems (BOS) costs make up 75% to 85% of the total cost in all cases. The study indicates that balance of system costs are sensitive to the PV efficiency, system configuration, and equipment design, with PV efficiency and configuration are the most effective avenues for BOS and system cost reductions. It is found that the dual-axis tracking is the least expensive configuration for a 5-MW PV plant now and at higher future PV efficiency. The authors stated that continuing construction of large-scale PV power plants would be the single effort that would stimulate component cost reduction through demand and produce innovative approaches. In addition, the authors suggested that some form of subsidy would make PV competitive both now and in the future.

Leonard [71] addressed some of the questions before PV can become economically and technically competitive. The author described the experience to date in the construction and operation of six recent PV power plants interconnected with the electric utility grids. In addition, the author discussed three recent large size PV power systems with capacity ranging from 100 to 200MW. The actual costs for the 1 MW-SMUD power plant in Sacramento were less than projected. Large scale system design studies confirm that array fields in PV plants must be divided into sub-fields so that the total reliability improves.

Herwig [49] discussed the PV technology advances, industry progress, and market promise. The author reported both long-term and near-term technical goals. According to this study, the price of installed power system ranges from \$7 to \$15 or more/peak kW depending upon the size and application of the system. Long-term balance of system costs are also reported. Area related costs range from \$50 to \$100/m^2. Power related costs are \$150/watt. These estimates are based on levelized electricity cost target of 6 ¢/kWh. For the near-term, the module cost ranges from \$90 to \$240/m^2 based on levelized electricity cost of 12 ¢/kWh. The author estimates that by the year 2000, there would be some 1000 MW connected to the electric utility grids.

Lund and Pino [73] explored the technical and economic feasibility of a PV power plant to be installed in Central Maryland in 1988. The purpose is to analyze the potential application of a commercially viable Grid-interactive 50 MW PV system. The total costs for the 50 MW plant was \$4373/kW and \$3391/kW for 15% and 20% efficiencies, respectively. The O&M costs were 3.2 ¢/kWh/year and 2.4 ¢/kWh/year. It was concluded that because of the minimal capacity value and the relatively high capital cost, the 50 MW PV system cannot be justified as an alternative at that time, unless capital costs are reduced. This is due to non-coincidence between the Baltimore Gas and Electric peak load and PV peak output. The production cost savings are estimated using the PV power output as a negative load. The O&M costs are layered onto the production costs outside of the program.

Hoffner [54] analyzed the performance of the city of Austin PV plant. The city of Austin Utility Department has been operating and maintaining a nominal 300 kW. Analyses of the one-year data indicate that the plant operated well, and was highly reliable with an availability of greater than 99 percent. The plant operated at a yearly capacity factor of 22 percent and a peaking capacity factor of about 55 percent during the utility's summer peak load hours. Plant operating and maintenance costs were 0.4¢ /kWh for the first year after removing all costs associated with research and start-up procedures. The yearly cost savings attributed to avoided fuel were about \$7800 or about 2¢ /kWh not including credits for avoided capacity, cost savings are due in part, to the relatively low fossil fuel costs in 1988 and because of the Utility's significant surplus electric generating capacity. In the mid-to-late 1990's, high fuel costs combined with significantly lower capital costs, large scale PV power plants would be competitive with conventional generation.

Krawiec [65] analyzed the impact of a PV system on a selected utility system production cost. The author used a scaled down version of EPRI Synthetic Utility "E" representing a southeastern utility. Two PV systems, rated 100 MW and 500 MW, are evaluated. A Detailed Static Simulation Model developed by the Advanced Systems Technology Division of Westinghouse Corporation is used to perform the simulations. The author concludes that several complex factors would affect the PV value. First, results indicate that fuel savings are affected by the penetration level, fuel prices, and generation mix. Second, the correlation between insolation and load is very important. Third, the break-even capital cost for a viable PV system varies from $400/kW to $770/kW for 5% and 1% penetration levels, respectively. These estimates are only good for the assumptions made in the study.

Tam and Rahman [133] recognized the advantages of using central station photovoltaics and fuel cells. Therefore, they propose an augmented power conditioning subsystem to improve the power system performance. According to the tests conducted on a 40 MW PV-Fuel cell system, the PV-Fuel cell central station reduces system real and reactive power losses from 13.3 MW to 8.82 MW and 25.83 MVAr to 9.53 MVAr, respectively. The central station system is found to reduce short circuit losses as well and offers other economics advantages.

Baron et al. [8] reported that solar resources in the Mid-Atlantic region of the United States is suitable for PV applications. According to this report, DOE contends that penetration of utility markets will begin when the 30-year levelized electricity costs from PV systems are in the range of 10 ¢/kWh. PV systems will compete with conventional generation sources when energy costs reach 6¢ /kWh. The requirements for dispersed PV applications may be significantly lower. On the other hand, according to the same survey, 96% of the utilities cited that PV systems will more useful in meeting peak demand, 88%

in meeting baseload, 90% reducing capital costs, 78% in adding capacity in small increments, and 85% in reducing environmental emissions. In addition, 41% of the respondents indicate that they are using or planning to use PV systems. Some other utilities are concerned about issues related to PV interface with the grid.

Finally, PV concentrator systems are expected to compete with peak-power and base-power generation. First, efficiencies of up to 27.2 percent are obtained. Experimental solar cell efficiencies are reported as high as 34.2 %. The increase in efficiency would reduce energy costs. Second, the Five Year Plan for the National PV-Program has established energy cost goals of 22¢ /kWh in the 1990's and 6¢ /kWh in the year 2000. At these costs, PV concentrator systems would compete with conventional peak-load and base-load generations.

Tables 3.1 through 3.5 summarize evolution of capital cost and O&M costs for several utilities across the US and overseas. The breakdown (c/kWh) of O&M costs is also shown in Table 3.3 and Figure 3.1. Figure 3.1 is based on average O&M costs from Table 3.3. These costs are function of solar cell technology, tracking mode, size, and year of construction.

Table 3.1 PV Project Cost Summary

Location	Plant Capacity (kW)	Project Cost ($/ kW) projected	Actual	Construction Year
Lovington (New Mexico)	85.9	21,490	32,460	1981
Beverly (Mass.)	84.4	23,140	35,770	1981
Sky Harbor (Phoenix)	169.1	31,480	27,430	1982
Lugo (Hesperia)	850.0	-	-	1982
SMUDPV1 (Sacramento)	1002.0	12,000	12,000	1984
PVUSA-1* (Davis, CA)	400.0		< 5,000	1991
Chur** (Switzerland)	110.0	-	14,890	1989
Wind Energy (Current)	-	-	1,000	1991

* Solar Today, May/June 1991
** Solar Today, August 1991

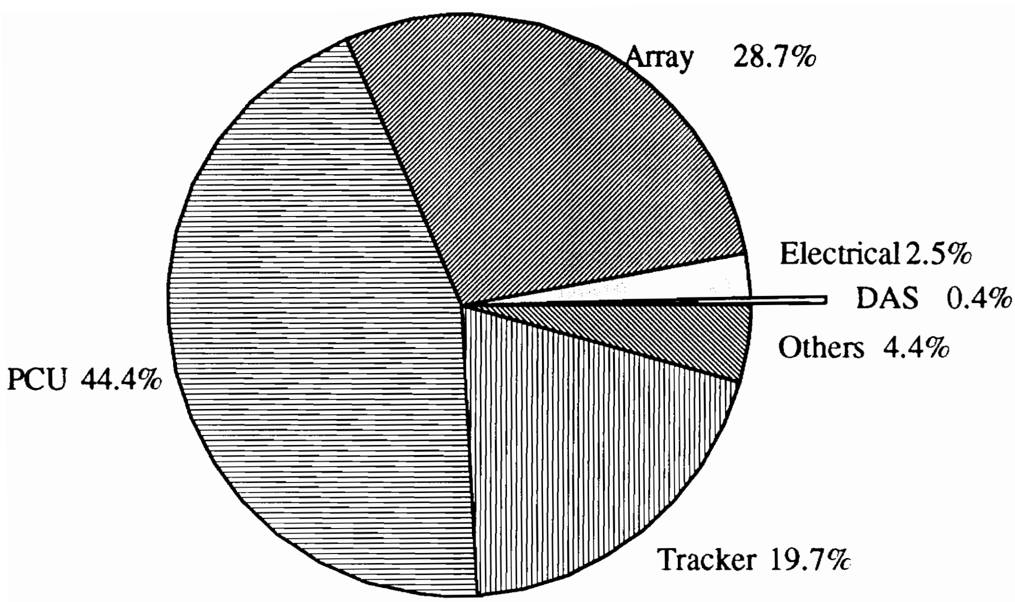
Table 3. 2 Actual O&M Costs (¢/kWh)

Location	Flat Fixed	Flat Two-Axis	Plate One-axis	Concentration Two-Axis	One-Axis
Lovington (New Mexico)	0.39				
Georgetown (Washington DC)	1.44				
Carrissa Plains (California)		0.80			
Lugo (Hesperia)			1.10		
SMUDPV1 (Sacramento)			0.61		
Sky Harbor (Phoenix)				4.81	
Dallas Ft. (Dallas)					6.97

Table 3.3 Actual and Average O&M Costs (¢/kWh)

Source [36]

Component	Range	Average
Data Acquisition System	0.00-0.03	0.009
Electrical	0.02-0.09	0.057
Array	0.00-2.51	0.661
Power Conditioning Unit	0.11-4.55	1.022
Tracker	0.02-1.78	0.454
Other	0.00-0.31	0.101
Total System	0.39-6.97	2.304



Total O&M Costs: 2.304 cents/kWh

Figure 3.1 Actual Average O&M Costs (¢/kWh)

Table 3.4 O&M Costs for Selected PV/Wind Energy Facilities (¢/kWh)

Source [36]

Site	Potential Actual O&M Costs	Known Problems Solved	Best Components	Higher Efficiency Cells
Carrissa Plains	0.10	0.50	0.29	0.20
Lugo	1.10	0.65	0.29	0.20
SMUD	0.61	0.22	0.15	0.13
Georgetown	1.44	0.73	0.14	0.12
Sky Harbor	4.81	1.12	0.53	0.30
Dallas Ft.	6.97	1.19	0.73	0.35
Lovington	0.39	0.35	0.13	0.11
Wind (current)	1.00			

Table 3.5 Cost of Energy (¢/kWh) (in constant 1987 dollars)

Technology	Low	High
Solar Thermal Hybrid	6.0	7.8
Nuclear	5.3	9.3
Natural Gas (Intermediate)	5.3	7.5
Hydro	5.2	18.9
Wind	4.7	7.2
Coal Boiler	4.5	7.0
Natural Gas (Combined Cycle)	4.4	5.0
Geothermal Flash Steam	4.3	6.8
Biomass Combustion	4.2	7.9

Source:[Solar Today May/June 1992]

3.4 Generation Expansion Planning

Bucciarelli [134] developed an approximate approach to evaluate the performance and the probability of loss-of-power of stand-alone photovoltaic solar energy systems. The method treats the energy capture, storage, and disbursement process as a random walk in the storage domain. The technique uses the variance and the mean of the probability density of the daily solar insolation. Analytical expressions are obtained for the probability of depleting the system's storage and for how much auxiliary energy, on the average, would be required to cover the load in that event.

Desrochers et al. [33] presented a method for determining the cost effectiveness of wind energy and the economic limitations of its penetration into electrical power systems. The study is based on Monte-Carlo approach which simulates the hour-by-hour operation of the power system. The hourly random variations in wind and load are modeled in addition to the operating constraints inherent in conventional generation. The economic assessment is based on selected one-year simulation period. Two examples of the application of the method were discussed.

Farghal and Abdel Aziz [40] studied the long-term competitiveness of introducing the renewable energy sources side-by-side with conventional generating units in a generation expansion plan by linking between the short-term study and the long-term planning model. In the short-term study, there is a chance to study extensively the different combinations of renewable energy sources which can operate with the conventional generation at different objectives. These objectives are varied between two general strategies; the fuel saver strategy and the peak shaving strategy. In the long-term planning, these combinations are considered as decision variables beside the conventional resources. For this purpose, the long-term generation expansion planning model is used to decide which strategy can be used and the capacity as well as the time of addition. This model is based on the decision tree concept which has enough flexibility and is capable of modeling the uncertainties inherent in the problem.

Fegan and Percival [41] demonstrated the equivalency of LOLP methods and Baleriaux-booth method for conventional energy sources and showed that the failure of the equivalency to hold in the case of intermittent sources is due to a correlation between load and energy availability and the use of hourly input data. The authors suggest alternative methods for calculating reliability measures for intermittent generation.

Ramakumar, et al. [88] recognized that the long range solution to the energy woes of the world does not lie in any one particular approach, and that combination among PV, wind, solar heat, tidal, and ocean thermal energy systems is the solution. The authors compare different capital cost for various power plants.

Peschon et al. [81] discussed the development of new mathematical models for the economic evaluation of intermittent energy sources, such as solar thermal, PV, tidal, small hydro, fuel cells, etc. The purpose of these models is to answer questions related to real-time operation problems, operating savings, economic characteristics for a 20-25 year planning period. The aim of the study is to estimate the present worth of benefit to cost of these energy sources and to predict their penetration level.

3.5 Short-Term System Operation

Unit commitment, economic dispatch, and automatic generation control are an integral part of short-term production cost. However, literature in unit commitment involving RES is limited. Only few efforts in this domain are known up to date. Because of the negative load concept assumed in integrating PV and wind energy sources, conventional unit commitment algorithms are applicable with minimum modifications.

Schlueter et al., Bakirtzis et al., and Chowdhury and Rahman have developed techniques dealing with many aspects of unit commitment and economic dispatch with PV and wind energy conversion systems.

Park and Schlueter [77] summarized the effects that various combinations of wind regime, array configuration and penetration, and system characteristics would have on system variables such as area control error, frequency, interchange power and spinning reserve. The characteristics of the combinations causing system operating stress or "operating problems" are assessed. Methods for reducing operating problems are suggested that involve array configurations, penetration, unit commitment and dispatch changes, and wind generator controls. The limitation of the work reported is not in the utility operations simulation, which is very detailed, but in the array models which have not been verified by experimental data from large wind generator arrays.

Schlueter et al. [96] proposed a modified unit commitment that would be updated on 24 hour and sub-hourly bases. The first would handle the effects of load and slow trend wind power change that could be predicted 24 hours ahead. The second would manage fast trend and cycle change in wind power that could be predicted one hour ahead, and quick change in wind power. Results indicate that wind generation penetration above 5% can cause loss of operating reliability and economy.

Kinloch, Wickson, and Becker [64] evaluated different wind generators. The study indicates that many of the detrimental effects of wind electric generation can be minimized or eliminated by using a diversity of small and large wind generators, using different designs of wind turbines and by using diversity wind areas. The study recommends that wind generation for utilities is more attractive if a diverse wind generation system is used.

Lee and Yamayee [70] investigated the load following and spinning reserve penalties for intermittent generation in the economic evaluation of such sources when connected to the electric grid. The authors incorporate the economic evaluation in an optimal generation expansion planning model which evaluates the effect of such requirements on the generation mix and the production costs The authors claim that the penalties are too high due to the presence of intermittent generation and that all energy and capacity credits are eliminated due to such penalties. According to a case study performed by the authors, increasing penetration of intermittent generation causes an increase in the spinning reserve requirements, thereby in the load following requirements, the increase being linear. The effect of penetration on system costs is found to be nonlinear. According to the study, a penetration level of less than 5%, the load following requirement is satisfied by the optimal generation mix, the penalty cost arising primarily due to increase in spinning reserve requirement. Beyond 5% penetration, the load following requirement begins to alter the generation mix, thus the penalty cost is greatly increased due to the combined effect of higher spinning reserve and departure from the optimal generation mix imposed by the load following constraint.

Perez and Stewart [80] addressed the relationship between the utility characteristics and solar energy resources. Utilities in the northeastern and Mid-Atlantic U.S. have summer peak load and summer peak PV output. This is very useful to maximize PV electricity use. Results indicate that the economic viability of PV application for immediate future is a more reasonable expectation than is conventionally assumed for the Northeastern utilities. Results indicate also that the economic feasibility should become a reality in the late nineties. The authors suggest that matching both seasonal and daily electricity demand peaks with the solar resources is vital and is recommended for northeastern U.S. utilities. Additionally, the authors suggest that utilities should investigate the utility impact of a large scale penetration of multi-kilowatt system on the utility grids and the corresponding resource monitoring and forecasting needs.

Bakirtzis et al. [7] presented a methodology for solving short-term generation scheduling problem in a small autonomous system with diesel generators, wind, and photovoltaic energy systems and storage battery. A dynamic program algorithm combined with a standard unit commitment is used. The algorithm takes into account the following constraints: the unit minimum up and down times, start-up cost, must-run and must-not run scheduling, and spinning reserves. However, ramping rates are not considered. Moreover, the wind and solar systems and the battery are operated cost-free. The methodology was implemented on a small utility with a 600-kW peak load. The energy cost reported was as low as 5.42 ¢/kWh.

Chinery and Wood [135] introduced a method to calculate the value of PV-generated power. The authors used the generation mix and unit commitment policy of the Tennessee Valley Authority (TVA) power system, the load shape experienced by TVA, and the weather data in Chattanooga, Tennessee. The calculations are carried out using measured data for the historical calendar year 1984. The calculations are repeated for each year of the 1985-2010 time frame using estimated values of PV system output and marginal costs of grid power. The expected value of PV-generated power for a typical residential 4 kW PV system ranges from 2.41 ¢/kWh in 1984 to 12.87 ¢/kWh in the year 2010. All costs are given in 1985 dollars.

Sloan and Vliet [103] investigated the influence of tracking orientation on the performance of grid-interactive single axis tracking flat-plate PV arrays in Austin, Texas. The authors chose the economic value of PV produced energy as the optimizing criterion. The economic value is based on the displaced fuel credit, capacity credit, and structural costs. High economic value was attributed to energy produced during peak load period. The study concluded that the optimum tracking configuration is greatly influenced by fuel costs. As fuel costs rise, the economic optimum tilt angle will slowly approach the optimum angle so as maximum energy is produced. For Austin, the optimum panel tilt angle for horizontal axes is 20 degrees.

Chalmers et al. [18] assessed the effect of grid-connected PV generation on the utility operation. Various PV concentrations and performance characteristics of generation control are studied. The results show that PV generation can be integrated into the utility system in substantial amounts without creating any unusual problems in the system operation and control. The most severe condition as reported by the authors is created when the entire PV array is completely covered and uncovered by a fast moving cloud. The simulation results show that the NERC limit is violated during winter when the PV penetration level exceeds 5.5%.

Chowdhury [24] proposed a new operational tools for integrating a photovoltaic system into the electric utility's generation mix. First, a modified dynamic dispatch algorithm is proposed that requires a Box-Jenkins time series method to forecast short-term photovoltaic power output. Second, the dispatch consists of rule-based algorithm which controls the non-committable generations to achieve an optimal solution. The rule base works in tandem with a conventional dispatch routine.

Gordon and Wenger [43] recognized that the optimal design of central-station PV systems depends on the field layout, PV array geometry, tracking constraints, and connections. For this reason, they studied the sensitivity of yearly PV system energy delivery losses due to inter-array shading as a function of key field, tracker, and array-related variables. Results are found to be independent of the site. The study is useful to predict energy losses due to shading which is a function of array inner-distance, the limitations on maximum tracker rotation angle, and the series and parallel electrical connections for multi-megawatt PV systems where significant energy delivery penalties and economic waste need to be avoided.

Chowdhury and Rahman [22] explored the short-term prediction of photovoltaic power output through forecast of global solar irradiance for sub-hourly time frame. This is very useful for unit commitment and economic dispatch study of power system connected with central station PV system. This is done by proposing a novel approach for the prediction of solar irradiance in the sub-hourly time frame (3-10 minutes) by means of Box and Jenkins time-series analysis.

Rahman and Chowdhury [82] discussed and tested the performance of central station photovoltaic. First, they examined and tested a number of photovoltaic performance analysis models for their ability to estimate the ac. power output, and validate those against historical measurements from a PV test station. Second, they developed a method to estimate meteorological parameters for use in PV performance models for predicting future ac power output from the PV system. 12 such performance models are examined. PVFORM model was found to provide the best predictions for ac power output.

Chowdhury and Rahman [22] proposed a new operational tool for integrating a photovoltaic system into the utility's generation mix. The development and implementation of a new approach a dynamic rule-based (RB) dispatch algorithm are presented, which takes into account the problems faced by the dispatch operator during a dispatch interval and channels those into rule base. The proposed dynamic dispatch requires forecasts of photovoltaic generations at the beginning of each dispatch interval.

A Box-Jenkins time-series method is extended to yield forecast parameters which are then used to predict the photovoltaic output expected to occur a certain lead times coinciding with the economic dispatch intervals. The RB is introduced to operate either as a substitute for or an aide to the dispatch operator. The RB gives one of 16 possible solutions, if required. These solutions are written as rules which manipulates the non-committable generation to achieve an optimal solution. It is concluded that results depend on the time of year and the specific utility. Also, the utility generating capacity mix significantly influences the results.

Chowdhury and Rahman [22] introduced a new operational tool for integrating central station photovoltaic power system into the utility's generation mix. The authors developed and implemented a dynamic rule-based dispatch algorithm. The new dispatch technique requires PV generation forecast at each dispatch interval. For a single day, base load and peak load generation decreased by 6.7% and 18.4%, respectively. The increase in spinning reserves was insignificant. The total production cost was reduced by 3.5%, which corresponds to $60,000 during the day. The authors reported that the worst situation occurred when load decreased and PV generation significantly increased in a short time period.

Chowdhury [23] investigated the value of photovoltaic plants to electric utilities under constraints of power system security. The generally adopted methods of analysis for determining the "capacity credit", "energy displacement", and "production cost savings" due to the PV plants have neglected the adverse conditions that may arise out of a random pre-selection of a substation where PV power is injected into the system. This paper presents an extensive approach at determining the realistic value of a PV plant to the utility. The method consists of using a power flow algorithm to determine system conditions under specific load scenarios. Identification of bus voltage violations and branch overloads is an integral part of the method. The location of the substation where PV is included is critical. Determination of system behavior under contingency conditions with and without PV is also investigated. This indicates whether the power system can withstand disturbances in the presence of PV power. The value of the PV plant can then be determined by finding the maximum PV penetration that would not cause the system to become insecure.

Contaxis et al. [29] developed an algorithm for determining the reliability and cost of operation of an autonomous energy system containing diesel units and wind generators over a period of time. The simulation period is divided into intervals of t minutes duration. Given the characteristics of the diesel and wind generators, the hourly loads, and the statistics of wind velocity, the algorithm finds the cost of operation and reliability of the system over each interval and the whole period for each commitment schedule alternative. The proposed algorithm is a module of an overall scheme used for comparing alternative commitment schedules in order to find the optimal one, i.e. the one which provides the minimum cost under a given reliability. The random nature of wind velocity and load demand is taken into consideration by utilizing stochastic models for the diesel and wind generator operation. Results obtained by the application of the algorithm to an autonomous energy system for a medium-size Greek island are reported.

Contaxis and Kabouris [30] assessed scheduling problems associated with wind power generation. In small autonomous energy systems, the wind power penetration may reduce drastically the cost of the produced energy. The solution of the short-term scheduling problem faces great difficulties because of the randomness of wind speed and power generation. This paper describes an algorithm developed at the National Technical University of Athens for determining the optimal operation scheduling over a period of hours for an autonomous energy system consisting of diesel units and wind generators.

The proposed method requires the solution of the following two problems- the short-term forecasting of load and wind velocity, and the short-term unit commitment. The proposed method is applied for a medium size Greek island.

Jewell et al. [60] presented the results of a study of the Public Service Company of Oklahoma (PSO) system with simulated dispersed generation. It was found that, with high penetrations of PV, as insolation changes, significant variations in power flows occurred on the transmission and sub-transmission lines that may require changes in system protection and voltage control practices.

Jewell and Ramakumar [59] presented the results of a simulation designed to assess the maximum possible changes in PV generation expected over certain time interval. The simulation can be used with power flow to study the actual effects of dispersed residential PV generation on the electric utility. The key findings are. First, the maximum changes in PV generation usually occur within 1-2 minutes. Second, longer intervals would no result in greater changes. Third, the maximum PV changes always occur during off-peak times. The results indicate that the effects of PV generation changes will be the greatest at the substation level, therefore proper protection and control would required.

Jewell and Unruh [61] investigated how a utility would determine its maximum allowable PV capacity and the value of this capacity. The study allows estimation of the maximum fluctuation in PV generation that the utility can withstand before inadvertent tie-line flows occurs and production costs increase. Results indicate that the utility needs to limit the size of the central station PV system to 1.51% of the system load to avoid inadvertent tie-line flows. For a dispersed PV system, this limit could approach 40%. In this study, no fast ramping generation is used. It is expected that combustion turbines would absorb these PV fluctuations and would enhance higher central station PV penetration.

Jewell et al. [136] addressed the effects of PV's dependence on sunlight. Investigators at the Wichita State University studied the cost and the effect on utility reliability of rapidly changing PV generation for a partly cloudy day. The authors proposed a methodology to assess the cost of fluctuations in PV generation and their effect on the utility's ability to serve the load. The authors presented a case study, on-going data collection, and the performance of two PV systems. A review of how PV generation is dispatched was also included in this paper.

Yamayee [114] proposed an approach to modeling renewable resources, in particular wind energy availability. The author recognizes the randomness of wind velocity at a given site and the randomness from one site to another, thereby, he suggests to have a model for uncertain wind energy availability. The model starts with historical hourly wind data at each site in the area covered by the Pacific Northwest Power Act. The obtained probability density functions are then used in a Monte-Carlo simulation environment to represent the uncertainty in wind energy availability. Theoretical and numerical examples are included.

Zaininger [116] presented results of a dynamic study of minute-to-minute ramping, frequency excursions and short-term transient stability of a power system containing wind power generations. The authors determined the allowable combined wind turbine cluster corresponding to a 0.1 Hz and 0.4 Hz frequency excursion.

Krebe and Starr [66] described the methodology for assessing the value of PV generated electricity for stand-alone and grid-connected operations. The authors use the avoided cost as a convenient basis for assessing the economic value of a PV system.

Economics models for PV systems, wind energy systems, diesel generators, and grid-extension are considered in the study. Results indicate that the PV value for grid-connected applications depends on several factors. The authors suggest that wind systems could be cheaper than PV systems for properly chosen locations. They also suggest that capital cost should decrease, transmission losses, and transmission costs should be reduced before the PV system would be viable.

Beyer, Luther, and Steinberger-Willms [9] reported that the integration of high percentage of PV power into the utility grid would give rise to several problems. This is due to high fluctuations in power input to the grid and unmatched time patterns of load and power generated. The authors suggest to overcome these problems. In fact, the utility should distribute PV generating capacity over large geographical areas and take advantage of decreasing correlation of insolation with increasing intersite distance. The authors looked at surplus energy generated in grids with a high percentage of PV power injected to the utility.

Kern, Gulachenster, and Kern [62] addressed slow transient responses at frequencies corresponding to fluctuations of PV generation due to cloud motion. The maximum ramp rate and the range of the ramp for the entire site can be estimated using the cloud modeling technique developed. For instance, during a 14-second transition interval, the power increased by 1140 %. The authors show the advantages of dispersed PV generation. For 75% excursions, the ramp rate was 10 %/second for a single system. For 60% excursions, the ramp rate recorded was 3%/second for 28 systems. This information is useful for unit commitment and economic dispatch.

3.6 System Capacity Factor and Capacity Credit

Alsema et al. [1] evaluated the capacity credit obtainable for PV systems integrated into the electric utility by making use of the Loss-of-Load Probability technique. The authors showed that the more diversified the PV system is, the higher the capacity credit is, and that the bigger the PV size is, the lower its capacity credit is. By shifting the maintenance schedule to the low peak season, the capacity credit would increase. In fact, the capacity credit was found to range from 28 percent to 15 percent for a 200-MW PV system and 2500-MW PV system respectively. These figures are lower for non dispersed PV systems.

Hoff and Shushnar [53] summarized the performance of the Carrissa Plains PV plant for 1984-1985. The capacity factor, reliability and peak load and peak PV power output were found to be high. The capacity factor ranged from 22% in January to 41% in June. During on-peak hours in the peak season, the capacity factor ranged from low 65% in July to high of 85% in June. This shows that the load matching method that would use an entire year's data powerfully shows the value of PV as a load matching technology, in general, and to Pacific and Gas Electric, in particular.

Rahman et al. [85] analyzed the performance of the Virginia Integrated Solar Test Arrays (VISTA) photovoltaic facility owned and operated by Virginia Power. Parameters such as the array efficiency, power conditioning unit efficiency, and capability factors of the sub-fields are studied. The authors concluded that large scale, grid connected PV facilities operation is feasible and it requires no intensive labor for the highly reliable modules.

3.7 PV and Energy Management

Chowdhury and Rahman [21] explored the impact of photovoltaic power generation on the electric utility's load shape under supply-side peak load demand management conditions. The PV system is backed up by fuel cells and storage battery. Different tracking options and combinations of PV with battery and fuel cells are considered. The work has suggested that western United States utilities capacity savings are higher than that of the southeastern utilities. In summer and fall, the PV power plant has a bigger impact in the typical western utility. The study helps utilities to decide on the type of tracking, backup and on maintenance schedules for both conventional and PV power plants.

Rahman, Jockell, and Lahouar [86] analyzed the effectiveness of PV system as a load management tool. The authors used the PV data of the Virginia Tech Solar Facility and load data of the building housing the Electrical Engineering Department. The impacts of integrating the PV system, building load data and the control are reported. The benefits include energy costs and demand capacity savings. These benefits are estimated at 6¢/kWh and $15/kW. The coincidence of peak load and peak PV output has enhanced the value of the PV system integration.

Cull and Eltimsahy [31] studied the progress in formulating energy management strategies for standalone PV systems, developing an analytical tool that can be used to investigate these strategies, applying this tool to determine the proper control algorithms and control variables (controller inputs and outputs) for a long range of applications, and quantifying the relative performance and economics when compared to systems that do not apply energy management. The analysis technique developed may be broadly applied to a variety of systems to determine the most appropriate energy management strategies, control variables and algorithms. The only inputs required are statistical distributions for stochastic energy inputs and outputs of the system and the system efficiency and capacity rating.

Vachtsevanos et al. [137] addressed the impact of distributed photovoltaic systems upon the utility load management operations. The approach is based on collection, analysis, and assessment of regional solar resources data and the development of a statistical insolation model depicting distribution of the available solar electric resource and the uncertainty associated with this availability; a stochastic model of electric power output of PV systems incorporating reliability characteristics of the PV system itself; and a comprehensive probabilistic simulation of the power systems to evaluate the impact of the PV systems on utility production costs and reliability. The model simulates random forced outages of units, economic dispatch practices, derating of units, stochastic load variations. A number of possible scenarios of PV system penetration are defined and analyzed using this methodology. The results of the analysis lead to the determination of the relative merits of alternative load/supply management scenarios based on the PV systems. A cost benefit analysis is used to determine the economic impact of PV systems on both the utility and the customer.

3.8 Dispatching Direct Load Control

Direct Load Control (DLC) involves the control of customer loads by an electric utility to achieve desirable load shape change to reduce peak load, shift energy requirements from peak to off-peak hours, and improve load factors by cycling off customers' loads. These loads include air conditioners, water heaters, swimming pool pumps, etc.. The ultimate objectives of DLC are to reduce system reserve requirements, reduce production and fuel costs, and improve generation system reliability performance.

The control interval and time-of-the day at which load control is performed, is decided upon mutual agreement between the electric utility and the customers so as to reduce customer's discomfort and avoid revenue loss to the utility. Traditionally, direct load control is performed in a static fashion. The amount and duration of load to be controlled are fixed, regardless of the fast and quick changes in the electric power system, with the expectation that the residual load will be satisfied with the available generation. Over the last few years, direct load control received greater consideration.

3.8.1 State of The Art in Direct Load Control

The work by Salehfar and Patton [138] describes the dynamics of DLC and an incremental cost scheme which are then coupled with a Monte Carlo simulation model of the operation of thermal generation. DLC has the characteristics of a dispatchable system resource which is available, whenever needed, to the system operator. It has a capacity which depends on the rated load under control, time of the day, season of the year, and customer life style. Six study cases of exogenous and dynamic direct load control are studied. For example, all the hourly demand above 80% of the system annual peak are exogenously deferred. Energy paybacks are made every night during low load hours starting at 11:00 p.m. and continuing for a period of six hours. The load threshold is varied in the second case. In the other cases, the control period length and payback intervals are varied to study the effects of dynamic load control. Total production costs and unserved energy are monitored. The net production cost savings due to DLC is computed as follows:

$$S = C_1 - C_2 - (E_1 - E_2) * R \qquad (3.1)$$

where

S = Net saving due to DLC (M$/yr)

C_1 = System production cost before DLC ($/yr)

C_2 = System production cost after DLC ($/yr)

E_1 = System generated energy before DLC (MWh/yr)

E_2 = System generated energy after DLC (MWh/yr)

R = Average customer rate ($/MWh)

The load control adopted in this study was intended to maximize reliability of the system rather than minimize production cost. In fact, the model can be used to study and assess alternative load control strategies. However, operational constraints have an important effect on the system production cost savings generated by DLC, but cannot be accounted for in long term operation. In fact, DLC can be most effectively integrated into system operation if it is made dispatchable over the 24-hour period, and if the dispatch intervals are optimally determined according to the changing system conditions.

Few years earlier, Bhatnagar and Rahman [139] setup the requirements of optimal direct load control based on the following two assumptions. First, DLC can be most effectively integrated into system operations if the dispatch is on-line. Second, DLC can be utilized for several different objectives on the same system at different times of the days such as fuel cost minimization, peak load shaving, system reserve contribution, emergency load shedding, and reserve margin capacity.

The author formulated a closed-form solution to DLC as a means to reduce fuel costs on a sub-hourly basis. It was found that the optimal solution at each stage is dependent only on the stage load and the cost characteristics of the on-line generators. Therefore, since the optimal solution is independent of previous stages, the optimum solution over the 24-hour period is the sum of the optimal solution of each stage. This would hold true if the generation level of on-line units is independent of the previous level. As shown in the economic dispatch solution, the power output of each on-line unit depends on system load at the moment, spinning reserve contribution, and particularly, on the unit's previous power output and ramping rates.

According to the study, the optimal load control to be dispatched is given by:

$$X_{dlc,opt} = \frac{A_1 - A_2}{2(B_1 - B_2)}$$

where

$$A_1 = \sum_{j=1}^{M_1} (Pd_{new,j} + b_j)/c_j$$

$$A_2 = \sum_{i=M_1+1}^{M_1+M_2} (f_i - d_i)*(Pd_{new,i} + b_i)/c_i \tag{3.2}$$

$$B_1 = \sum_{j=1}^{M_1} 1/2c_j$$

$$B_2 = \sum_{i=M_1+1}^{M_1+M_2} (f_i - d_i)^2/2c_j$$

and for each stage k

$$b_k = \sum_{i=1}^{N_k} \frac{\beta_i}{2\gamma_i}$$

$$c_k = \sum_{i=1}^{N_k} \frac{1}{2\gamma_i} \tag{3.3}$$

$$a_k = \sum_{i=1}^{N_k} \alpha_i$$

where α_i, β_i, and γ_i are the fuel cost coefficients for unit i and N_k is the total number of on-line units at stage k.

During the control period, the new load

$$Pd_{new,k} = Pd_k - Pd_{dlc} \tag{3.4}$$

And during the payback period, the new load

$$Pd_{new,k} = Pd_k - (f - d) X_{dlc} \tag{3.5}$$

where

X_{dlc}, f, and d are the amount of DLC dispatched (MW), total restrike demand per MW of DLC, and normal diversified demand per MW of DLC, respectively.

The closed-form solution for the cost/savings due to DLC dispatch has been developed in terms of the system loads and the cost characteristics of the on-line power plants. Therefore, it accounts for both, the load shape and economic impacts of direct load control.

The implementation of the solution requires a computation of the stage parameters a_k, b_k, and c_k, but if the set of generators does not change, then the computational burden can be reduced by using values calculated for the previous state.

The proposed dynamic DLC model was coordinated with unit commitment in the following matter. The DLC dispatch is simulated over 24 hours to obtain the modified load curve. The modified load curve is then input to the unit commitment program to obtain the new unit commitment. Winter and summer loads were used to assess the impact of the dynamic DLC on fuel costs savings, peak load shaving.

To achieve maximum production cost savings, DLC dispatch must be coordinated with economy functions such as economic dispatch and unit commitment. A more dynamic DLC model has been recently developed by Hsu and Su [140], in which direct load control combined with unit commitment is dispatched using dynamic programming. If the amount of load reduction is $Y_{DLC}(n)$, then the payback pattern, Z_{pb} and modified load L(N) are given by:

$$\begin{aligned}
Z_{pb}(n+1) &= a_1 * Y_{dlc}(n) \\
Z_{pb}(n+2) &= a_2 * Y_{dlc}(n) \\
Z_{pb}(n+3) &= a_3 * Y_{dlc}(n) \\
with \quad & a_1 + a_2 + a_3 = 1.0
\end{aligned} \tag{3.6}$$

and

$$\begin{aligned}
L_{new}(n) = L_{old}(n) - Y_{dlc}(n) + Z_{pb}(n-1) \\
+ Z_{pd}(n-2) + Z_{pb}(n-3)
\end{aligned} \tag{3.7}$$

where $L_{old}(n)$ and $L_{new}(n)$ are the load before and after load control, respectively.

The unit commitment and economic dispatch are then performed to optimize dispatching load control subject to maximum and minimum load control, dispatching intervals, and hydroelectric availability. Results indicate the effectiveness of load control based on dynamic programming, that the proposed dynamic programming approach yields a variable amount of load control for each stage over the load control period and higher fuel costing savings compared to static direct load control.

3.8.2 Coordination of Photovoltaics with Demand Side Management

The effectiveness of photovoltaics as a load management device is a function of the match between the peak load and the peak PV power output. Due to the high demand charges associated with the price of electricity at peak hours, it may be cost-effective to use such a free energy source to reduce the need for electricity supplied by the electric utility. In the future, reducing the peak load becomes critical. In fact, electric utilities are planning to bill the customer throughout the year for exceeding their demand allowances even for a short period of time. In the many studies conducted so far, the value of photovoltaics is assessed as a source of electricity. The underlying assumption is that the PV facility is owned by the utility and would dispatch to reduce energy cost and improve service quality. However, as load management devices, small PV facilities are installed by the customers to reduce their demand. In the study of Rahman *et al.* [128], such an arrangement was evaluated. A PV forecasting system and a load management system were interfaced. The former predicted the PV power output, while the latter computed the load control to be implemented based on the load, PV power output and control options.

Similarly, Chowdhury and Rahman [21] explored the impact of photovoltaic power generation on the electric utility's load shape under supply-side peak load demand management conditions.

Cull and Eltimsahy [31] studied the progress in formulating energy management strategies for stand-alone PV systems. The analysis technique developed may be broadly applied to a variety of systems to determine the most appropriate energy management strategies, control variables and algorithms.

Vachtsevanos, Meliopoulos, and Paraskevopoulos [137] address the impact of distributed photovoltaic systems upon the utility load management operations. A number of possible scenarios of PV system penetration are defined and analyzed. The results of the analysis lead to the determination of the relative merits of alternative load/supply management scenarios based on PV systems. A cost benefit analysis is used to determine the economic impact of PV systems on both utilities and customers.

It is the function of control center to coordinate direct load control dispatch with that of the PV system so as to minimize the overall production cost while maintaining the amount of load control as low as possible. The ultimate target is to know when, where and how many air conditioners, water heater need to be cycled. Such a coordination was successfully implemented for the power system onboard the space station. The same could be extended to the electric utility. Small electric utility systems such as Virginia Tech system in Blacksburg, Virginia would benefit from the proposed technique, where the power system consists of few conventional energy sources.

3.9 Fuel Cells and Storage Backup

Khallat and Rahman [63] and Khallat [119] developed a concept and study results of adding fuel cell to provide operational support to PV systems. The objective was to determine the capacity credit of PV systems included in the utility generation mix. A capacity expansion study had been presented which determines the upper limit of the penetration level of the PV systems in the electric utility. In addition, the applicability of this concept in the short-term operational time frame had been tested using economic dispatch models. The concept had been tested using the observed performance data of a PV facility, and the system data of a typical southeastern US utility. Fuel cell power plants had been added to the generation mix, and their effect on increasing the penetration level of PV generation is monitored. It had been found that after certain penetration level, the net capacity credit for PV systems started to decrease.

Rahman and Tam [84] studied the feasibility of photovoltaic-fuel cell hybrid energy system. The paper presents the concept and feasibility study results of applying fuel cells to provide operational support to photovoltaic arrays. Through simulation using actual data, it is shown that it is feasible to use fuel cell in coordination with PV to meet variable loads for either utility or standalone applications. The dynamic response required of the fuel cell to support the hybrid operation is found to be well within the capabilities of the prototype designs that have been tested in the United States and Japan. The hybrid operation overcomes the intermittency problem inherited with the PV power output and provides new applications for the fuel cell technology.

Tam and Rahman [133] recognized the advantages of using central station photovoltaics and fuel cells. Therefore, they propose an augmented power conditioning subsystem to improve the power system performance. According to the tests conducted on a 40 MW PV/Fuel cell system, the PV/Fuel cell central station reduces system real and reactive power losses from 13.3 MW to 8.82 MW and 25.83 MVAr to 9.53 MVAr, respectively. The central station system is found to reduce short circuit losses as well. In addition, the PV/fuel system offers other economics advantages.

3.10 Resources Assessment

Jabbour [58] developed a computer simulation model to study the short-run value of electricity generated by private entities and offered for sale to the electric utility. The model can determine the short-run value of the non-utility generated electricity. It is assumed that variable operational costs production will remain constant for any penetration level. The several scenarios performed using this model indicate that the short-run value average value of non-utility generation does not necessarily lie between the two marginal costs of the utility and that the short-term value increases with the steadiness of the power output. The level of increase is small and it depends largely on the increase of start-up costs.

3.11 Advances in Economic Dispatch

In the last decade, several different economic dispatch programs and algorithms have been developed. Many of these programs solve the unit commitment using techniques based on partial enumeration method, dynamic programming method, Bender's partitioning method, heuristic method, Lagrangian relaxation method or mixed integer-linear programming method. Application of Artificial Intelligence and Neural Network has been recently initiated. The economic dispatch and automatic generation control problem has been investigated as well.

3.11.1 Static Economic Dispatch

The majority of static economic dispatch studies have been one form or another of optimal load flow. In these studies, a convex representation of costs is assumed in the algorithm. Given these assumptions, the methods implemented for static economic dispatch differ with regard to the manner of representation of system losses and the nature of the proposed solution. Luo et al. have proposed an economic dispatch model analog to conventional network model, wherein incremental bus costs play the role of bus voltages, generator powers play the role of source currents, and the parameters of quadratic bus cost curves play that of source voltages and source and branch impedances. The proposed economic dispatch problem can be solved using conventional network solution routines and it includes transmission losses. However, general production costs must be represented by quadratic functions. Moreover, the response rate constraints are not recognized.

Guoyu, Galiani, and Low [44] introduced a participation-factor vector into a two stage solution algorithm, thus eliminating slack bus. The proposed method does not depend on the slack bus. In addition, for systems using participation factors, these are directly available and provide closed-loop realization. Unfortunately, the method requires the use of monotonic cost curves, and does not include response rate constraints.

Happ [47] proposed an economic dispatch procedure for allocating generation in a power system by the use of the Jacobian matrix. The major advantages of the procedure over other optimal dispatch procedures is its inherent simplicity and rapid convergence behavior which are characteristics particularly important for on-line implementation. Results obtained from an investigation of its convergence for the 118 bus IEEE system are given. Comparisons with classical approach are conducted and logic for on-line implementation is presented.

3.11.2 Dynamic Optimal Dispatch

Considerations of dynamic dispatch were initiated by Bechert and Kwatny in 1972, and Patton in 1973. Since then, interest in the problem has continued at a relatively low level. Heuristic solutions have been proposed by Wood [113] and Isoda [57]. Ross and Kim [91] utilized successive-approximation dynamic programming. Mukai et al. [142] formulated and solved a dual problem to minimize a Lagrangian by iteration. Van den Bosch [143] formulates a non-linear programming problem that takes into account spinning reserve requirements, and then solves the problem using the gradient projection method along with conjugate search directions. Van den Bosch and Honderd [144] propose a solution to the unit commitment problem using decomposition and dynamic programming. The solution of the dynamic optimal dispatch is constrained by both reserve requirements and power rate limits. The method combines non-linear programming with conjugate search directions.

Ramping rates are very crucial to the economic dispatch problem. They shape up the generating unit instantaneous capabilities to respond to the changes in system load, and maintaining sufficient spinning reserve margins. Stadlin [106] and Fink et al. [145] have addressed these issues.

Stadlin [106] incorporated an additional constraint of regulating margin into the economic dispatch optimization. He introduced the term μ to be the Lagrangian multiplier representing the incremental cost of regulating margin in \$/MWh. Modification of the conventional incremental cost was made possible by introducing the regulating margin cost penalty.

Somuah and Schweppee [105] reformulated the economic dispatch problem by adding a constraint on maximum frequency deviation following a postulated disturbance. The difference between the frequency deviation constrained dispatch and the conventional economic dispatch was the allocation of total system margin. With a tight minimum frequency limit, the allocation was made so that the system margin is distributed among more units with the faster units. The authors used Dantzig-Wolfe's decomposition technique combined with several linear programming solutions.

Somuah et al. [104] considered dispatch problems that involve the allocation of system generation optimally among generating units while tracking a load curve and observing power rate limits of the units, system spinning reserve requirements and other security constraints. The authors investigated the use of two methods to solve the problem. The first method is quadratic programming technique combined with a linear programming Redispatch technique. The second method utilizes a linear programming formulation of the dynamic dispatch problem about the base case Static Economic Dispatch Solution. The second method is based on the Dantzig Wolfe's Decomposition Technique. Tests and simulation results show the advantages of the two proposed techniques.

Wood [113] proposed a heuristic method to solve the economic dispatch problem using search routine. Unit response rates are observed and security capacity margins are maintained. The proposed method is robust, efficient and compatible with conventional static dispatch algorithms. However, the method assumes that future load is deterministic, and because of its heuristic nature, the method does not provide the optimal solution.

Similarly, Isoda [57] proposed a heuristic, but a true dynamic dispatch method. The proposed procedure incorporates a load dispatch. That is, it calculates trajectories for all units such that the forecast load will be satisfied at the least cost subject to response rate limits constraints. The method provides true dynamic economic dispatch and it can be used in an on-line load dispatching center as well as off-line. However, the method has not been tested.

Dillon et al. [34] developed a method for determining unit commitment schedule using extensions and modifications of the Branch and Bound method for integer programming. The proposed method is capable of handling all constraints on the schedule. It is computationally practical for realistic systems and proper representation of the reserves associated with different risk levels.

Schulte et al. [98] discussed the different problems associated with unit commitment in uncertainty. The major uncertainty factors are load forecast uncertainty, thermal unit startup cost, maintenance schedule, and power transaction data. According to the report, startup cost uncertainty has the largest impact on unit commitment decisions. The authors caution utilities to account for uncertainty associated with cogenerators, wind energy, solar and small hydro systems, and interchange with neighboring utilities. The BENCHMARK power simulator is discussed in this survey that uses heuristic unit commitment. It is believed that the model is capable of handling all constraints, with one exception, it uses hour by hour simulation.

In several power system production programs, cost minimization disregards environmental concerns and logistics constraints. Heslin and Hobbs [50] recognize the need for multi-objective production costing model to include constraints such as emissions dispatching and fuel switching. The model uses state-of-the art probabilistic production costing methods.

Modeling pre-defined unit hourly start-up ramps can cause problem that require new programming tools. Hobbs et al. [52] examined this issue and utilized and enhanced dynamic programming (DP) for unit commitment. The DP-based method supports realistic modeling of unit start-up ramps and analyses solutions that can be overlooked under traditional methods.

Chowdhury and Rahman [21-23] proposed a new operational tool for integrating a photovoltaic system into the utility's generation mix. The development and implementation of a new approach-a dynamic rule-based (RB) dispatch algorithm are presented, which takes into account the problems faced by the dispatch operator. The new dynamic dispatch requires forecast of photovoltaic generations at the beginning of each dispatch interval. A Box-Jenkins time-series method is used to yield forecast parameters which are then used to predict the photovoltaic power output expected to occur a certain lead times coinciding with the economic dispatch interval. The RB is introduced to operate either as a substitute for or an aide to the dispatch operator. These solutions are written as rules which manipulate the non-committable generation to achieve an optimal solution. It is concluded that results depend on the time of year and the electric utility. Also, the utility generating capacity mix significantly influences the results.

Aoki and Satoh [2] presented a new method to solve the economic load dispatch problem with DC load flow type network security constraints. The network security constraints represent the branch flow limits on the normal network and the network circuit outages. Hence, the problem contains a large number of linear constraints. In power systems, only a small number of flow limits may become active. The authors extended the quadratic programming technique into the parametric quadratic programming method using the relaxation method. The memory requirements and execution times suggest that the method is practical for real-time applications.

Zhuang and Galiana [117] proposed a new Lagrangian relaxation algorithm for unit commitment. The algorithm proceeds in three phases. In the first phase, the Lagrangian dual of the unit commitment is maximized with standard sub-gradient techniques. The second phase finds a reserve-feasible dual solution, followed by a third phase of economic dispatch. The proposed algorithm has been tested on systems of up to 100 units to be scheduled over 168 hours, giving a reliable performance and low execution times. Both spinning and time-limited reserve constraints are included in the problem.

Chen and Yang [146] proposed a recursive computational procedure derived from the cumulant method. It is stated that production cost and reliability of generation system can be evaluated by probabilistic production simulation. The derivatives of production cost and reliability refer to the changes of simulation results due to marginal variation of a specific system parameter, which may be an hourly load level, or the unit capacity or forced outage rate of a generating unit. The recursive procedure is applicable to the derivatives with respect to load, unit capacity, or forced outage rate. Moreover, the procedure could handle any number of cumulants without additional theoretical development of software implementation effort. The general accuracy of this procedure and three applications are discussed.

Chowdhury [23] investigated the value of photovoltaic plants to electric utilities under constraints of power system security. The generally adopted methods of analysis for determining the "capacity credit", "energy displacement", and "production cost savings" due to the PV plants have neglected the adverse conditions that may arise out of a random pre-selection of a substation where PV power is injected into the system. This work presents an extensive approach at determining the realistic value of a PV plant to the utility. The method consists of using a power flow algorithm to determine system conditions under specific load scenarios and identify bus voltage violations and branch overloads. The location of the substation where PV is included is considered critical. Determination of system behavior under contingency conditions with and without PV is also investigated to determine whether the power system can withstand disturbances in the presence of PV power system. The value of the PV plant can then be determined by finding the maximum PV penetration that does not cause the system to become insecure. The analysis is applicable to any size power system.

Chowdhury and Billinton [25] formulated a probabilistic technique to evaluate the additional interruptible load carrying capability of a generation system without having to commit any extra unit than that required to sustain the firm load. This study provides insight regarding load interruption and sudden load increments when capacity adjustments cannot be done within a specific time period. The developed technique is illustrated with numerical examples. The technique can be applied to short and medium term operational planning.

Chowdhury, N. [27] presented a reliability constrained unit commitment in interconnected systems with continually changing loads. The author formulated a probabilistic technique which can be used to develop unit commitment schedules for continually changing loads in an interconnected system configuration for a specified period. This approach, known also as the 'Two Risk Concept', was illustrated in a recent publication. The unit commitment during a specified scheduling period is constrained by risk criteria and economic factors.

Chowdhury and Billinton [26] presented a risk constrained unit loading technique for interconnected systems, which utilizes a least costly deviation from economic load dispatch to satisfy the risk criteria. The technique was developed on the basis of each area in a multi-area configuration fulfilling two different response risk criteria.

Chowdhury and Billinton [147] developed a probabilistic method to assess import and or spinning reserve purchase requirements of interconnected systems in order to overcome the effects of inadequate operating capacity on unit commitment risk. A unit commitment technique which can include options of spinning reserve purchase/sale is presented. An approach to assess the portion of the running cost in interconnected systems due to export/import and purchase of spinning reserve is presented in this paper as well.

Handschin et al. [45] recognized the existing of long-term constraints in the unit commitment problems. To account for these constraints, the authors propose a unit commitment in thermal power systems with long term energy constraints.

Innorta et al. [56] presented a dynamic approach to the real power dispatch of thermal units suitable for time periods characterized by high rates of load variation. Therefore, dynamic dispatch uses its look-ahead capability at the disposal of the system operators to predict how present loading and its gradient would influence the response rate ability of the units at a future time. The authors used a suitably modified version of the Han-Powell algorithm in a compact reduced model. Sparseness technique is used in the construction and in updating the Hessian matrix of the Lagrangian function.

Lee [68] presented a short-term fuel constrained thermal unit commitment method designed for Oklahoma Gas and Electric Co. which has significant fuel constraints including take-or-pay gas contracts and limitations associated with the gas delivery system. These fuel constraints are explicitly considered in determining the short-term thermal unit commitment strategy. This method resulted from successful application of a novel unit commitment approach to a complex fuel constrained problem and it is very effective in both its computational requirements and its solution quality.

Lee [69] presented a new approach for determining the priority order of thermal unit commitment. In this approach, a new Commitment Utilization Factor (CUF) index is used in conjunction with the classical economic index AFLC (average full load cost) to determine the priority commitment order. Based on the author's application experience, the proposed approach is very effective because the resulting priority commitment orders are consistently better, whenever possible, than those determined by the AFLC index alone. This approach can be easily implemented as an add-on module to an existing priority-order-based unit commitment model. The addition can significantly improve the performance of the model without noticeable penalty in the computational requirements. In this paper, a midwestern utility system is used to illustrate the proposed approach.

Lin, Hong, and Chuko [72] proposed a real time fast economic dispatch method by calculating the penalty factors from a base case data base. The basic strategy of the proposed method assumes that a base case data base of economic dispatch solution is established according to statistical average of system operation data of the daily demand curve. Solutions in the data base can either be calculated by the B-coefficients method or other existing methods in the literature.

Patton [79] introduced the concept of dynamic optimal dispatch as opposed to the static optimization, which does not consider the effect of change related costs. The dynamic optimal dispatch method uses forecasts of system load to develop optimal generator output trajectories. Generators are then driven along the optimal trajectories by the action of a feedback controller. Optimal trajectories are first calculated for nominal load forecasts using quadratic programming or gradient projection methods; then they are updated using neighboring optimum methods as load forecasts are revised through time. Studies of small system indicate that the dynamic optimal dispatch may be economically attractive. Savings of up to 1% of total fuel consumption are possible using dynamic optimal dispatch rather than static dispatch.

Raithel et al. [87] introduced a successive approximation dynamic programming to obtain the optimal unit generation trajectories that meet the predicted system load. They use dynamic optimization as compared to the static case. The dispatch program determines the economic allocation of generation for the entire future period of interest, using knowledge of both the present and the predicted load. The look-ahead capability provides the advantage of responding to sudden severe changes in load demand. They adapt the successive approximations dynamic programming algorithm to handle valve-point loading of units. Valve-point loading is included in the unit production cost function.

Ramanathan [89] discussed a fast solution technique for economic dispatch, based on the penalty factors from Newton's method. The algorithm uses a closed form expression for the calculation of the Lagrangian multiplier lambda and takes care of total transmission loss changes due to generation change, thereby avoiding any iterative processes in the calculations. In this algorithm, a major portion of the calculation time is spent on performing penalty factor calculations and is the same regardless of the calculation technique. Since, no iterations are involved, there are no oscillations or convergence problems in the execution of the algorithm.

Ross et al. [92] discussed the application of a dynamic economic dispatch algorithm to automatic generation control. When coupled with a short term load predictor, look-ahead capability is provided by the dynamic dispatch, that coordinates predicted load changes with the rate of response capability of generating units. The dispatch algorithm also enables valve-point loading of generating units. The method that the authors employ in their dispatch algorithm makes use of successive approximations dynamic programming. The authors claim that the algorithm is an improvement over the existing dynamic dispatch algorithms, in that the computer resources requirements are modest.

Ruzic and Rajakovic [93] developed an original approach for solving extended unit commitment problem using the Lagrangian relaxation method. The unit Commitment state of the art considers the unit ramp rates in the simplified heuristic manner. In this paper, the unit ramp rates have been incorporated into a dual optimization algorithm, giving a possibility of application of the feasible direction method for primal problem solution. The mathematical model developed in this paper also includes the transmission capacity group of units, transmission losses and fuel constraints. Standard unit commitment constraints such as power balance equations, fast spinning reserve constraints and all local constraints have also been taken into account. A computational package has been developed and tested over 48 hours time horizon and yield promising performances. Results indicate that this package suitable for energy management systems applications.

Sheble [100] developed a real-time economic dispatch algorithm suitable for on-line generation control and for study programs. The method is based on the rules of linear programming and the Classical method of merit order loading. The basis for the algorithm is shown as a neutral progression of classical optimization algorithms. The proposed method is very suitable for real-time economic dispatch on any energy management system. The method requires little computer resource and is appropriate for personal computer implementation as a part of a back-up automatic generation control system.

Sheble [99] proposed a heuristic solution for short-term thermal unit commitment. The algorithm has been developed using FORTRAN. Tests of this algorithm on data provided by a midwest utility have demonstrated satisfactory results. The proposed algorithm produces the same unit commitment schedule as a standard dynamic programming (DP) based algorithm in one fourth the computation time for the DP based algorithm. The algorithm is nearly linear with the number of unit periods. A unit period is defined as the on-line duration time versus operation level for each unit.

Virmani et al. [110] presented an understanding of the practical aspects of the Lagrangian Relaxation methodology for solving the thermal unit commitment problem. The Lagrangian relaxation method offers a new approach for solving complex, mixed-integer, non-linear programming subject to several constraints. Essentially, the method involves decomposition of the given problem into a sequence of master problems and sub-problems. The methodology was tested using a 20 unit power system.

Zhuang and Galiana [118] proposed a general optimization method, known as simulated annealing and apply to generation unit commitment. Simulated annealing generates feasible solutions randomly and moves among these solutions using a strategy leading to a global minimum with high probabilities. The method assumes no specific problem structures and is highly flexible in handling unit commitment constraints. A concise introduction to the method is included in this paper. Numerical results on test systems of up to 100 units show that the method can yield near-optimal solutions, that the method can be much faster than dynamic programming, and that the method can easily accommodate complicating factors such as crew and short-term maintenance constraints.

3.11.3 Expert Systems And Neural Networks Applications in Power Systems

The integration of human knowledge, knowledge base, pattern recognition, and artificial intelligence proves to be useful in power system operation. Similarly, Neural Networks based algorithms have been developed.

Power system operations consists of several complex tasks that need to be solved and monitored within a short time. At the mean time, computer hardware and software capabilities eases solving such problems. Following is a discussion of existing algorithms used in power system operation.

Matsuda and Akimoto [75] highlighted the potential of Neural Network in power system applications. Representation of large numbers in Neural Networks and its application to economical load dispatching are discussed in this work.

Mokhtari, Singh, and Wollenberg [76] developed a unit commitment expert system. The unit commitment expert system based consultant is developed to assist power system operators in scheduling the operation of generating units. It is one of the scheduling functions on the Salt River Project EMS system. The expert system answers the most frequent questions raised by system operators. It includes the operational constraints not included in the unit commitment base algorithm. Numerical examples and test results show that this approach can obtain a better and operationally more acceptable unit commitment solution.

Sakaguchi et al. [95] presented a survey of expert systems for power system operation from methodological and systems points of view. First, the logic-and heuristic-based methodologies for dealing with knowledge in computer software -the core of expert systems- are outlined. This is followed by an overview of the current applications and limitations of expert systems in power system operation. Finally, the future possibilities and prospects are evaluated.

Dash and Rahman [32] proposed a thermal unit commitment using Artificial Intelligence techniques. The unit commitment uses constraints search technique. A comparison has been made between different methods of search and between commitments with dispatching by straight line cost curve approximation and quadratic cost curve approximation. Results of comparison are given in this work. The advantages of this method over other methods being used for commitment are also discussed.

Fuster and Jelavic [42] recognized the potential applications of knowledge-based techniques in power system operations. The authors introduced a new knowledge-based system for weekly power system operation scheduling due to the fact that in weekly power system operations scheduling domain exists a number of improperly structured constraints which are difficult to solve by algorithmic approach. The knowledge-based system is proposed to handle normal system behavior as well as emergency cases such as lack of water inflows, generator outage, network problems etc. The proposed weekly scheduler includes load forecasting, inflows prediction, possible run-of-river hydro production, storage hydro production, unit commitment, generator maintenance and power interchange between interconnected power systems. The need for the proposed intelligent tool is recognized by the power utility due to the expected benefits such as minimization of generation costs and increase in reliability level.

Yokoyama et al. [115] presented an expert system application to support power system operators in emergency control against branch overload. The proposed approach considers generation rescheduling, line switching, and load shedding operation as corrective control options. Control rules are derived from analytical equations. The authors have employed a multi-stage decision process to formulate the problem of dynamic real power control. The proposed method is based on simplified procedures for software development and maintenance by separating the control strategy from numerical calculations. Model analysis demonstrates the superiority of this approach using a personal computer-based expert system.

Wollenberg and Sakaguchi [111] identified the potentials and needs for Artificial Intelligence (AI) in the above areas. The application of artificial intelligence in the unit commitment and economic dispatch is growing. Broader implementation of AI in the power system planning both on short and long-terms is critically needed. In fact, energy management, load forecasting, unit commitment/scheduling, and integration of customer-owned/renewable energy sources become complementary and interdependent. Due to this complexity, the application of AI would enhance this interdependence. The coexistence of these practices and the integration of the different energy sources require this tool. This will insure the full use of the operator skills and the expert systems extended capability. Areas that need complete understanding operation in a more complex power systems are good candidates for AI applications. Such areas are contingency analysis, state estimation, external model estimation, data sanity acquisition, automatic generation control, interchange evaluation, optimal load flow, load shedding, and trouble call analysis.

CHAPTER 4.

SYSTEM PERFORMANCE

The three facilities listed in Table 4.1 are considered:

4.1 VISTA Facility

The 60-kWp VISTA facility is located approximately 40 miles north-north-east of Richmond, Virginia. The latitude and longitude of the site are 38.075° North and 77.994° West respectively. The site encloses an area of approximately 2.2 acres. In addition to the three subfields, the site includes the data acquisition equipment, control tracking computer, and power conditioning subsystems.

The VISTA facility has been operational since December 1985. It consists of 3 customer-sized (20 kW AC) subfields comprising a larger (60 kW AC) test facility.

Sub-field A The northern most subfield, is composed of 8 two-axis tracking arrays each with 25 Solarex Polycrystalline PM-132/1 modules installed. Arrays are placed in east-west rows with an offset to reduce shadowing between structures. The total array area is 267.2 m^2.

Sub-field B The center subfield, also uses the same number of Solarex PM-132/1 modules as Sub-field A except has a fixed tilt array structure oriented to the south. The total array area is 267.2 m^2. Tilt angle may be varied manually. Four groups of array structures are arranged in two rows of two each. Each east-west row of structures forms an independent source with 100 modules each.

Sub-field C The southern most subfield is also a fixed tilt array structure similar to Subfield B. This subfield has 576 ARCO M53 single crystal modules on 6 groups of arrays structures. The total array is area is 214 m^2. There are two rows of three arrays across with each east-west row forming an independent source circuit. There are a total of 6 source circuits.

Power Conditioning Units (PCU)

The Power Conditioning Units (PCU's) convert the nominal 400 V dc output from the photovoltaic arrays to 480 volt 60 Hz AC power suitable for introduction into the electric utility grid. All controls necessary for unattended fully automatic operation are resident in the PCU's. Three PCU units rated 25 kW (ac) each are used in the photovoltaic facility. These units are identified as PCU-A, PCU-B, and PCU-C and are connected to Subfields A, B, and C respectively.

The three PCU's are identical in design and made by Omnion Power Engineering Corp. Their specification and control descriptions are listed in Table 4.2. The PCU's feature automatic unattended operation in all modes including startup and synchronization, normal running, shutdown, and out-of-limits shutdown conditions. The units are intended to normally operate in the peak power tracking mode with the capability of fixed voltage operation that is manually adjustable. The PCU's track the maximum power point voltage of the array to capture a minimum of 99% (?) of the available energy. Array current is limited or clamped when the array output is above the PCU maximum power rating.

The PCU will shut down and disconnect from the AC source within 20 cycles and disconnect from the DC array source circuits under any of the following conditions:

• Utility source voltage out-of-limits (greater than ± 10 percent of nominal) for greater than 5 seconds.

• Utility source frequency out-of-limits (greater than ± 2Hz) for greater than 2 seconds.

• Loss of utility source.

• Direct current input under voltage or fault.

• PCU internal failure such as over temperature or phase unbalance.

The PCU will automatically restart with a 2 minute time delay if the utility source returns to a "within" limits condition. This restart is applicable to voltage, frequency, and loss-of-utility-source shutdown conditions only. If three consecutive restarts fail, the unit will lockout and remain in the lockout condition until manually restarted. The tilt angles for each sub-field are listed in Table 4.3

4.2 VTSTF Facility

The VTSTF consists of 3 distinct components- the photovoltaic test bed, the building load data acquisition system, and the meteorological station. The facility is located on the uppermost roof of the Electrical Engineering Department building, the Va. Tech campus, Blacksburg, Virginia.

Photovoltaic Test Bed

The photovoltaic test bed consists of 3 independent photovoltaic arrays A, B, and C. The Array A is rated at 954 watts peak (dc) and consists of ARCO Solar M55 single crystal silicon modules. Array B is rated at 680 watts peak (dc) of ARCO Solar G4000 amorphous silicon modules, and Array C is rated at 626 watts peak (dc) of Solarex SA-20 amorphous silicon modules. Each array uses an Omnion Series 2000 PCU, rated at 2 kW each (DC input). The AC output of each PCU is fed directly into the electrical grid of the building. All arrays face due south and are mounted in a fixed tilt mode. The tilt angle can be adjusted as desired. Each array is made up of 2 sets of modules in series connection. The PCU's are designed to handle a 450 volt dc input and provide a 115 volt 60 Hz output. The M55 array has approximately 310 volt dc output, and its PCU is designed to handle the reduced input voltage by the addition of a transformer to boost the output to the appropriate level. For 1990, the tilt angle for each array was set as follows:

4.3 Raleigh Facility

This facility is located in New Hill, North Carolina. The latitude and longitude of the test site are 35.7° and 78.8° respectively [129]. The facility operation started in December 1984. The PV facility is a flexible, representative system featuring an array of polycrystalline silicon modules, and a current sourced and self-commutated PCU. The total array area is 64 m^2.

The PV array consists of 135 PV modules configured as 9 parallel strings of 15 series-connected modules. These are Solarex Model SX-120 modules featuring polycrystalline silicon cell technology. They are nominally rated at 40-watt, 17.5-Vdc, 2.3-Adc modules. It follows that the array is nominally a 236-Vdc, 21-A (dc), 4.9-kW array (assuming 10% losses due to mismatch). The array is a flat-plate due south and is adjustable in 5° increments between 25° and 40°. AC power output data for April 1987 were not available.

The PCU (APCC model UI-4000) is a self-commutated, current-sourced, DC-to-AC power converter incorporating maximum-power-point-tracking (MPPT) for the array, ac and dc contactors, an isolation transformer, and a control system that fully automates the operation of the PV system.

Table 4.1 Photovoltaic Facilities Characteristics

Station	Location	Rated Capacity
VISTA (Subfield B)	Richmond	20.000 kW (ac)
VTSTF (M55)	Virginia Tech	0.954 kW (dc)
Raleigh	Raleigh (North Carolina)	4.900 kW (dc)

Table 4.2. PCU Specification and Control Descriptions

Nominal Input Voltage	360 Volt dc
Input Voltage Tracking Range	313 to 406 Volt dc
Maximum Input Voltage (non operating)	480 Volt AC 3 phase, 60 Hz
Maximum AC Voltage	576 Volt AC (continuous)
Power Factor at 1/2 Load	0.90 leading
Power Factor at Full Load	0.90 lagging
Maximum Output Current	65 Amps AC
Maximum Output Rating	25 kW AC
Startup Power Level	1.6 kW dc
Standby Power Consumption	500 W dc
Efficiency at 10% load	89.00%
25% load	94.25%
50% load	95.10%
75% load	95.20%
100% load	95.10%

Source: [127,128]

Table 4.3 Tilt Angle Changes for 1990 for VISTA

Subfield	A	B	C
Quarter 1*	5°	27.5°	27.5°
Quarter 2	5°	27.5°	27.5°
Quarter 3	5°	27.5°	27.5°
Quarter 4	5°	27.5°	27.5°

* Tilt angles for Sub-fields A, B and C for Jan. 1989 are 0°, 0°, and 57.5°.

Table 4.4 Tilt Angle Changes for 1990 for VTSTF

Subfield	SA20	M55	G4000
Quarter 1	25°	27°	27°
Quarter 2	25°	27°	27°
Quarter 3	25°	27°	27°
Quarter 4	40°	40°	40°

Source 128

4.4 PV System Performance and Requirements

In this section, hourly, 10-minute, and 1-minute PV performance for selected PV stations is studied. Section 1 covers PV system performance. In Section 2, the reactive power requirements are evaluated using 1990 data.

4.4.1 Distributed and Mixed Technology PV Systems

The three operating PV facilities described in the previous sections are considered in this study. The purpose is to assess the individual and the distributed PV system performance and power requirements of these facilities. The study involves the sub-hourly ac power output variations, ramping rates, load following capabilities, and reactive power requirements. The selected facilities exhibit distributed and mixed solar cell technologies and tracking options.

Overall PV system availability depends on the availability of energy resources, hardware, and data acquisition system (DAS). The resource availability is a function of the weather conditions and site specifics and time of the year. Hardware availability depends primarily on solar panel operating state, tracking device, and power conditioning unit (PCU) trips and start-up level. In general, the PCU has a minimum start-up power level, below which no dc/ac conversion is possible. Finally, the DAS availability depends on transducer and data logger availability. These factors would influence the PV system overall availability. While taking into account these factors, great efforts are made to gather data relevant to the same period of time. This was not possible because the selected PV stations were not operating simultaneously.

Definitions

Ramping rates, load carrying capability, and system availability are important indices to determine the value of PV system. Ramping rate, also known as response rate, is the power output change within a specified time frame, usually one minute. For PV systems, the response rate is a function of prevailing weather conditions changes and solar cell technology. Load carrying capability is the additional amount of load that can be carried on top of the load without committing any additional units than that required to satisfy the firm load. This additional load must not violate the minimum unit commitment risk level. Allowable additional loads and lead times can be determined on a one minute to two hour time frame basis. For PV system, the additional load depends on weather and time of the day. While load carrying capability and system availability are as important as the ramping rates, only the latter is studied. This stems from the fact ramping rates are among the variables that influences economic dispatch solution, automatic generation control, and load frequency control. On the other hand, system availability is the probability that the system is operating at a specified time and is a function of resource, hardware, and data acquisition system availability. Moreover, PV system availability is useful for planning purposes.

The ramping rate (RR_t) for a power system at time t can be defined as:

$$RR_t = 100 \times \frac{(PV_{t+1} - PV_t)}{\Delta T \times PV_{rated}} \qquad (4.1)$$

where

PV_t and PV_{t+1} are the PV system power output at times t and t+1, respectively, in MW,

PV_{rated} is the PV system rated capacity in MW,

ΔT is the time resolution in minutes,

RR_t: is the ramping rate in %/minute.

Similarly, the load rate of change *(LCR_t)* at time t can be defined as:

$$LCR_t = 100 \times \frac{(D_{t+1} - D_t)}{\Delta T \times D_{peak}} \qquad (4.2)$$

where

D_t and D_{t+1} are the loads at times t and t+1, respectively in MW

D_{peak} is the peak load of the day in MW,

LCR_t is the load change rate, in %/minute.

Finally, the load fluctuation ($\Delta\ D_t$) is expressed as:

$$\Delta D_t = (D_{t+1} - D_t) - (PV_{t+1} - PV_t) \qquad (4.3)$$

where ΔD_t is load fluctuation in MW.

To study the variations of ramping rates, load change rate, and effective load changes, selected PV stations in Virginia and North Carolina are considered. Results include individual PV facilities and distributed PV systems. Comparisons are made for hourly, 10-minute and one minute data. The PV system is rated at 1000 MW.

4.4.2 Theoretical Ramping Rates

To assess the intermittency of the PV power output, ramping rates of the system must be compared to ramping rates (of what)? under clear weather conditions for each day of the year. The intermittency index is expressed as the sum of the squares of the difference between the actual rates of change and theoretical rate of change. Model development and results are based on fixed-tilt PV arrays, as is the case for VTSTF, VISTA, and Raleigh.

4.4.3 Results and Discussions

Hourly, 10-minute, and 1-minute data are used to study the ramping rates, load changes, and effective load changes as described above. Selected days were considered.

Table 4.5 displays the daily maximum PV power output fluctuations and load variations for January 2, April 12, July 3, and October 3. These days are selected because of their intermittent PV power outputs. Table 4.6 displays the corresponding ac output increase/decrease for a 1000-MW PV system. The distributed PV system has lower ramping rates than each of the three facilities. In addition, it has steadier effective capacity changes. For the distributed PV system, the ramping up capability was found to vary from 168 MW in October to 285 MW in January. While the ramping down capability varied from 137 MW in October to 314 MW in April.

Table 4.7 displays the daily extreme PV power output fluctuations and load variations for January 2, April 12, July 3, and October 3 for 10-minute time frame. Table 4.8 displays the ramping up/down capacity for the 1000-MW PV system.

In general, the ramping rates for the 10-minute time intervals are higher than those for the 60-minute case. Moreover, the 10-minute power fluctuations for the distributed PV system match load variations, a matter that did not occur for any single site. However, the power output fluctuations for VISTA, VTSTF, and Raleigh PV systems were more severe and in general exceed ed load fluctuations.

Tables 4.9 and 4.10 display maximum and minimum ac output and variations, maximum ramp-up and ramp-down rates for the 10-minute and 1-minute intervals at VTSTF. The study period starts at 2:46 p.m., Tuesday March 17 and ends at 11:02 p.m., Thursday March 19, 1992. The daily maximum and minimum power outputs for 10 and 1-minutes are shown in the first two rows of Tables 4.9 and 4.10.

For Tuesday and because of good weather conditions, the maximum 10-minute ramp up and ramp down rates reached 0.24%/min and -1.06 %/min for the M55 PV array. However, for the 1-minute time frame, the maximum values are 21.24 and -18.70 %/minute, respectively. The 1-minute rates for the mixed technology system are much lower than any other array (0.30 and -0.25 %/minute). This is in spite of the facts that the three arrays mounted side-by-side.

The 1-minute data show higher variations than the 10-minute case. The third and fourth rows display the maximum power output increase/decrease between two consecutive intervals. The last two rows show the maximum rate of change (percent per minute) for the single and mixed technology PV systems. The 10-minute rate of change is close to that of the system available to automatic generation control. However, the 1-minute rate of change can cause large power mismatches and lead to operational problems due to excessive thermal stresses. Even though the arrays are mounted side-by-side, their rates of change vary from one array to another. The overall rate of change of the mixed technology is lower than the average of the three rates of change.

4.4.4 Conclusion

Through this short study, two conclusions can made. First, for a PV system distributed across the utility service area, the overall PV generation changes are steadier than those for a centralized PV system. Second, mixed technology systems have lower ramping rates than for single technologies. Results indicate that the overall PV ramping rates can be reduced by a factor of three or higher and that the overall generation change can match the system load variations. In addition, while the overall PV capacity was lower than the sum of the individual rated capacities, a good percentage of PV generation still exists and it is available over a longer a period of time. This tends to improve the PV system reliability. Less power fluctuations would reduce scheduling peaking units that otherwise would result in start-up cost and interchange energy. Finally, it is expected that the impact of distributed PV system on the transmission and distribution network would be evenly spread. Moreover, the reactive power requirements would stabilize as shown in Section 4.4.5. Second, it is evident that monitoring the PV system every 10-minute would not reveal faster and shorter PV system dynamics whose size and frequency are critical for both economic dispatch and generation control. It is expected that much higher ramping rates and PV system dynamics can exist within a time frame of 30 seconds or less. For example, study by Kern et al. [1988] reported 10 % and 3 % per second ramp rates for a single system and dispersed system, respectively.

These two claims have been carefully considered in this dissertation. The proposed short-term system operation algorithm is designed to handle distributed PV system under severe weather conditions as well as steady weather conditions. Next the reactive power requirements are discussed.

4.4.5 Reactive Power Requirements For PV Systems

Inverter seems to be line-commutated

The economic dispatch optimization can and would involve reactive power and reactive transmission losses. The objective is to ensure that reactive power loadings of generating equipment remain within tolerable limits according to the unit's capability curve. With the presence of PV systems, the reactive power balance of the system has to account for the reactive power requirements of the PV system. In fact, while PV system can reduce reactive power demand and losses, more reactive power would be needed to support the voltage at the sub-station where PV system is installed. When the PCU operates at low loading (50 % loading or less), a reactive power is drawn from the grid. (?) With the increase of PV penetration levels, the reactive power requirements would be

Table 4.5 Maximum Hourly Ramping Rates and Load Changes for Selected Days

Day (Peak Load MW)	VISTA	VTSTF	Raleigh	Distributed	Load
January 2 (8134)	+0.23 -0.25	+0.49 -0.60	+0.71 -0.69	+0.48 -0.42	+0.21 -0.09
April 12 (6873)	+0.64 -1.12	+0.44 -0.76	+0.31 -0.34	+0.36 -0.52	+0.11 -0.05
July 3 (9420)	+0.35 -0.34	+0.34 -0.28	+0.43 -0.42	+0.32 -0.27	+0.16 -0.09
October 3 (7732)	+0.42 -0.43	+0.43 -0.25	+0.39 -0.45	+0.28 -0.23	+0.22 -0.07

All entries are in (%/minute) unless indicated otherwise

Table 4.6 Maximum Hourly PV Power Output and Load Variations (MW)

Day (Peak Load MW)	VISTA	VTSTF	Raleigh	Distributed	Load
January 2 (8134)	135 -149	294 -358	428 -415	285 -252	1041 -415
April 12 (6873)	383 -672	266 -457	187 -201	216 -314	436 -204
July 3 (9420)	212 -205	203 -170	257 -254	193 -164	925 -548
October 3 (7732)	252 -259	257 -149	233 -272	168 -137	1013 -319

Table 4.7 Maximum Ramping Rates and Load Changes (%/minute) (10-minute performance)

Day (Peak Load MW)	VISTA	VTSTF	Raleigh	Distributed	Load
January 2 (8279)	+2.30 -1.35	+0.56 -1.78	+6.33 -5.83	+2.18 -2.01	+0.34 -0.17
April 12 (7002)	+5.03 -5.99	+5.20 -5.49	+5.28 -3.19	+2.56 -3.11	+0.36 -0.26
July 3 (9433)	+4.99 -3.70	+0.69 -0.68	+5.92 -6.33	+2.51 -2.86	+0.14 -0.09
October 3 (7864)	+1.99 -1.57	+0.82 -1.70	+3.08 -6.20	+1.25 -2.20	+0.68 -0.42

Table 4.8 10-minute PV Power Output and Load Variations (MW)

Day (Peak Load MW)	VISTA	VTSTF	Raleigh	Distributed	Load
January 2 (8279)	+230 -135	+56 -178	+633 -583	+218 -201	+281 -141
April 12 (7002)	+503 -599	+520 -549	+528 -319	+256 -311	+249 -183
July 3 (9433)	+499 -370	+69 -68	+592 -633	+251 -286	+131 - 84
October 3 (7864)	+199 -157	+82 -170	+308 -620	+125 -220	+536 -328

Table 4.9 10-minute PV Power Output and Load Variations for Selected Days

Day (Peak Load MW)	VISTA	VTSTF	Raleigh (North Carolina)	Mixed Technology
January 2	281	281	546	281
(8279)	-278	-144	-672	-257
April 12	570	552	282	272
(7002)	-542	-541	-548	-339
July 3	410	131	679	326
(9433)	-459	-68	-552	-211
October 1	554	552	610	493
(8163)	-328	-320	-328	-325

Table 4.10 10-Minute and 1-minute Performance for VTSTF March 17, 1992 [2:46 p.m. - 12:00 a.m.]

	SA 20 Solarex		M 55 ArcoSolar		G4000 ArcoSolar		Mixed Technology	
	10-minute	1-minute	10-minute	1-minute	10-minute	1-minute	10-minute	1-minute
Maximum AC Power (watt)	292	324	602	663	167	188	1061	1175
Minimum AC Power (watt)	6	0	9	0	4	1	32	22
Maximum Power Rise (watt)	5	75	19	176	6	38	5	89
Maximum Power Drop (watt)	38	54	82	155	24	23	43	68
Ramp-Up (%/min)	0.11	14.82	0.24	21.24	0.14	12.93	0.03	5.58
Ramp-Down (%/min)	0.85	10.66	1.06	18.70	0.57	7.83	0.25	4.30
Maximum Power Rise (MW)*	11[a]	148[b]	24	212	14	129	3	59
Maximum Power Drop (MW)*	85[a]	106[b]	106	187	57	78	25	43

* This is based on a 1000-MW PV System   [a] For 10 minutes   [b] For 1 minute

Table 4.11 10-Minute and 1-minute Performance for VTSTF
March 19, 1992 [12:01 am - 11:02 p.m.]

	SA20		M55		G4000		Mixed Technology	
	10-minute	1-minute	10-minute	1-minute	10-minute	1-minute	10-minute	1-minute
Maximum AC Power (watt)	409	478	746	861	277	312	1432	1651
Minimum AC Power (watt)	2	0	6	1	3	0	23	15
Maximum Power Rise (watt)	168	241	313	465	125	173	607	852
Maximum Power Drop (watt)	159	287	292	523	111	198	558	1008
Ramp-Up (%/min)	2.70	39.10	3.30	48.70	1.80	25.40	2.70	37.80
Ramp-Down (%/min)	2.60	46.50	3.10	54.80	1.60	29.10	2.50	44.80
Maximum Power Rise (MW)*	270[a]	391[b]	330	487	180	254	270	378
Maximum Power Drop (MW)*	260[a]	465[b]	310	548	160	291	250	448

* This is based on a 1000-MW PV System [a] For 10 minutes [b] For 1 minute

significant, and would increase system losses. In this section, the reactive power requirements are quantified. The reactive power requirements can be included in the optimal reactive power dispatch solution to account for the PV system. For the purpose of this study, VISTA Subfield B is considered. Reactive power is injected into the grid if the PCU operates at 50% loading or higher and is drawn from the grid otherwise. Table 4.12 lists real and reactive powers for Sub-field B (VISTA) for 1990. Table 4.13 displays the monthly and annual reactive power requirements. The regression models for the reactive power requirements are also included. The proposed model is:

$$Q = A_0 + A_1 \times P + A_2 \times P^2 \qquad (4.4)$$

where

Q is the reactive power (KVAr);

A_0, A_1, and A_2 are the regression coefficients; and

P is the real power (KW)

Data with zero real or reactive power values are not considered in the model. Figures 4.1 and 4.2 display the daily profile for real and reactive powers for Richmond, during a sunny day in February and a cloudy day in October.

4.4.6 Results and Discussions

For August, September, and October, the daily reactive power is positive, that is on the average, the PV system drew more reactive power from the utility grid than it supplied. For the other months, the daily demand is negative, i.e., the PV system injected more reactive power than it drew. In general, the reactive power at the peaking hour is positive and ranges from 26.5 to 48.5% of the peak power output.

Results shown in Tables 4.12 and 4.13 indicate that the reactive power demand varies significantly with the time of the day and season. Moreover, at peak PV power output, reactive power demand reached 40% of the PV system rated capacity.

It is anticipated that diversified PV system would draw lower reactive power quantities from the grid because the PV sub-systems would operate at different levels and thus would either receive from or supply reactive power to the utility grid. In fact, while some sub-systems receive reactive power at low power output, others would supply reactive power to the utility at high generation level.

Table 4.12 Reactive Power Requirements for Sub-field B (1990)

Month	Real Peak Power (kW)	Monthly Real Power (kWh)*	Daily Real Power (kWh)*	Reactive Peak Demand (kW)	Monthly Reactive Power (kVAR)*	Daily ** Reactive Power (kVAr)*
January	na	na	na	na	na	na
February	23.50	917.00	91.70	7.16	-401.00	-14.30
March	23.90	2253.40	93.90	9.73	-627.70	-21.60
April	23.50	1404.90	100.40	9.11	-292.60	-10.10
May	22.53	2666.10	106.60	9.54	-863.20	-27.80
June	21.02	3430.50	132.90	10.19	-436.60	-14.60
July	19.02	2049.60	97.60	7.89	-885.90	-28.60
August	19.02	538.70	89.80	7.27	272.70	8.80
September	20.61	2384.40	91.70	7.67	1301.00	43.40
October	20.44	2166.60	86.70	7.79	1184.70	38.20
November	20.64	2614.70	93.40	5.63	-512.30	-18.30
December	20.05	750.60	53.60	5.32	-460.50	-32.90

* Down days are not included in computing daily/monthly powers.

**Negative entry indicates reactive energy/power received.

Table 4.13 Regressed Reactive Power for Sub-field B* (1990)

Month	Coefficient A_0	Coefficient A_1	Coefficient A_2	R^2
January	na	na	na	na
February	-10.628	0.432	0.0125	0.939
March	-10.964	0.612	0.0113	0.940
April	-10.718	0.449	0.0187	0.977
May	-11.023	0.613	0.0169	0.978
June	-11.101	0.744	0.0135	0.980
July	-11.201	0.785	0.0121	0.982
August	2.457	0.372	-0.0063	0.950
September	2.643	0.329	-0.0043	0.962
October	2.588	0.366	-0.0057	0.968
November	-10.358	0.442	0.0201	0.943
December	-10.296	0.332	0.0196	0.940
Annual	-8.245	0.649	0.0058	0.622

* Down days are not included in computing the real and reactive powers.

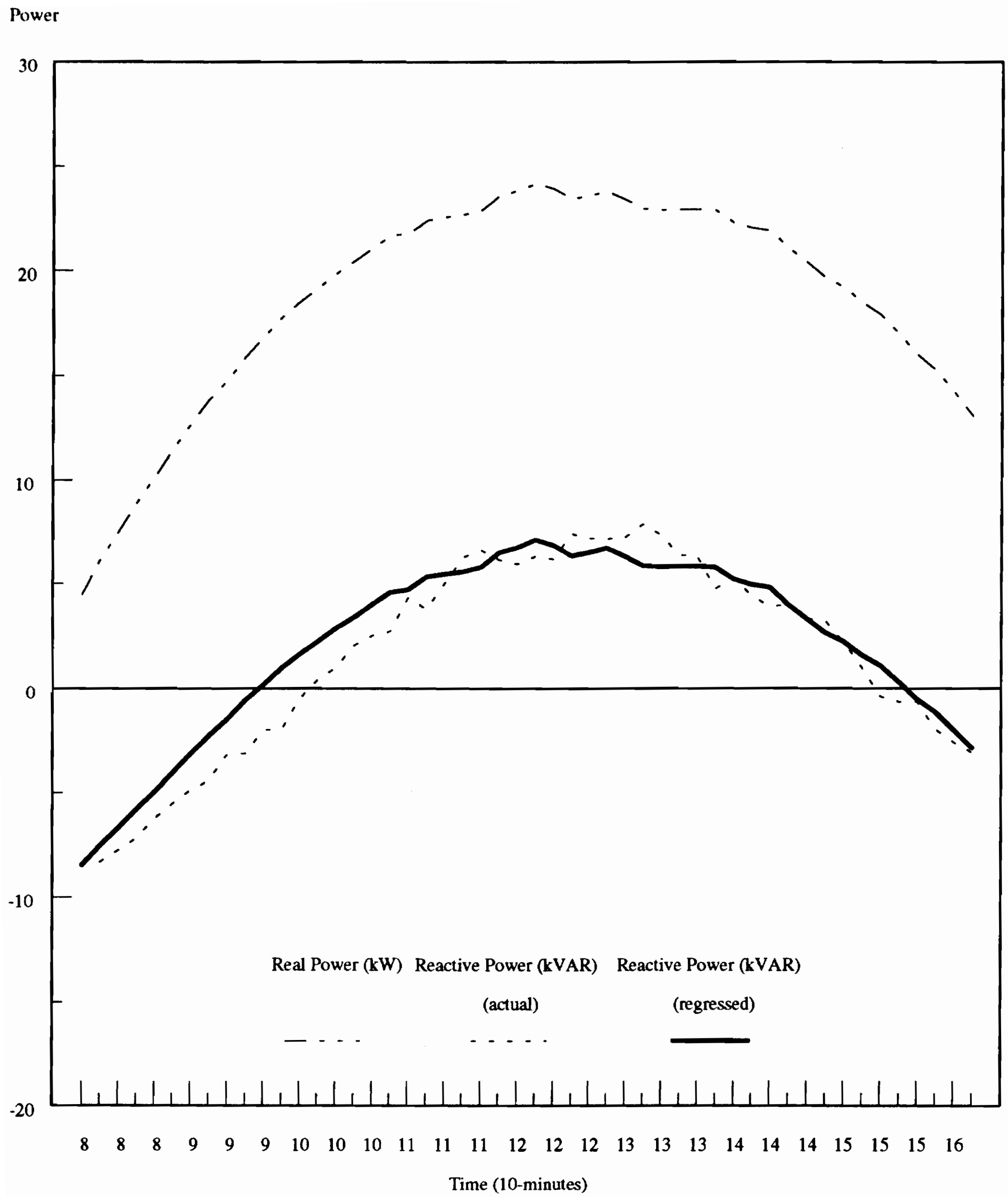


Figure 4.1 Real and Reactive Power Profiles for VISTA, Sunny day in February

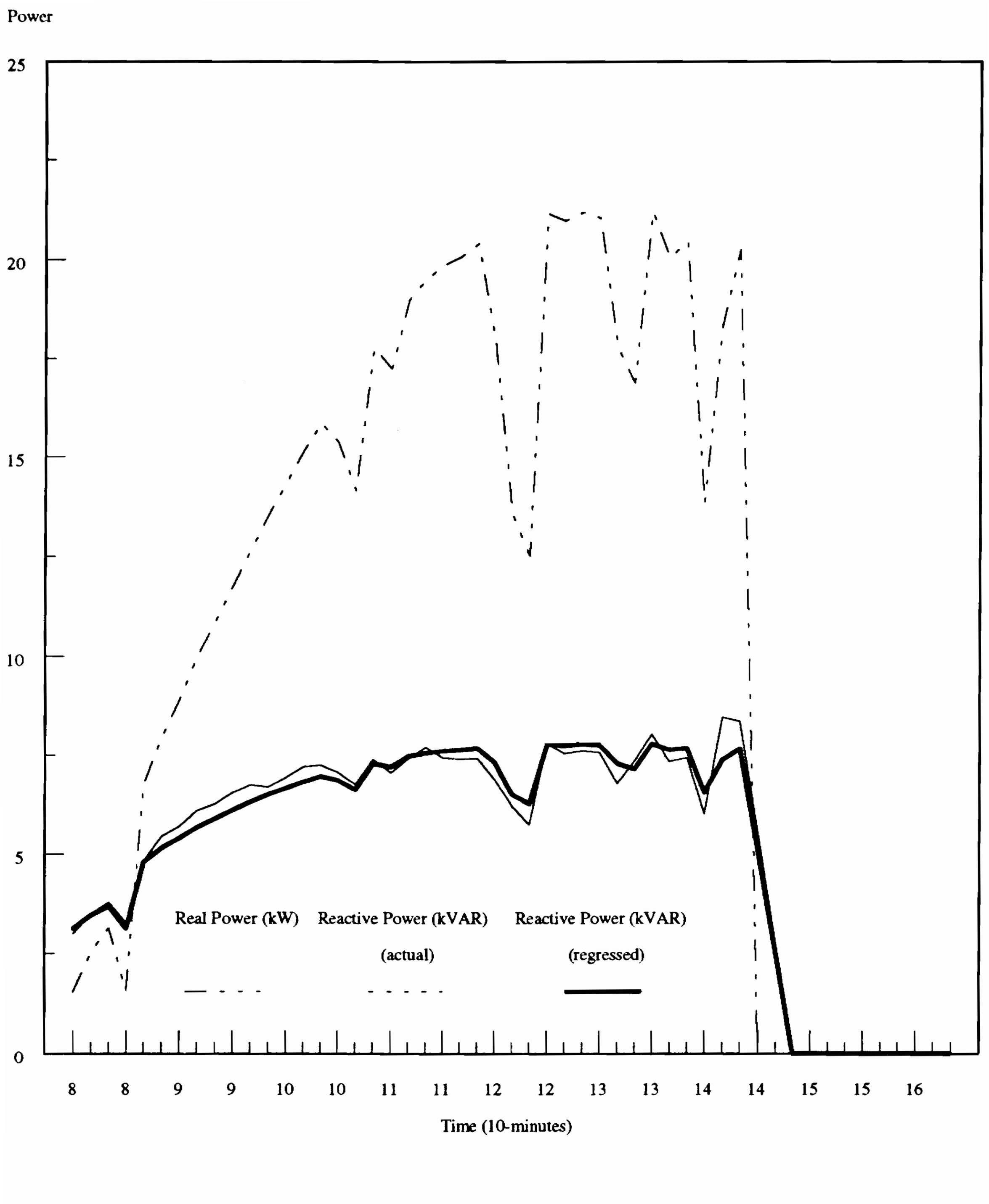


Figure 4.2 Real and Reactive Power Profiles for VISTA, Cloudy day in October

CHAPTER 5.

RESOURCE SCHEDULING AND UNIT COMMITMENT

5.1 Yearly Planning

Long term planning studies involving renewable energy systems have been conducted. Their purpose was to evaluate the system overall reliability, loss-of-load probability, and unserved energy on one hand and the capacity credit of the renewable energy systems on the other hand, among other performance indices. They are also to study alternative planning scenarios over a period of 10 to 30 years. Several existing long-term planning packages were used. Among these are the Wien Automatic System Planning Package (WASP) and the Electric Generation Expansion Analysis System (EGEAS). Even though the purpose of this dissertation is not to study multi-year generation planning, it becomes evident to investigate the electric system performance on a weekly basis with and without renewable energy systems. Since maintenance and repair schedules of power plants span from one week to five weeks, the one year study is adequate to study the variation of these maintenance schedules with and without renewable energy sources. For this purpose, PICES package developed by ONRL is used. First a description of the package is presented, then a case study is presented.

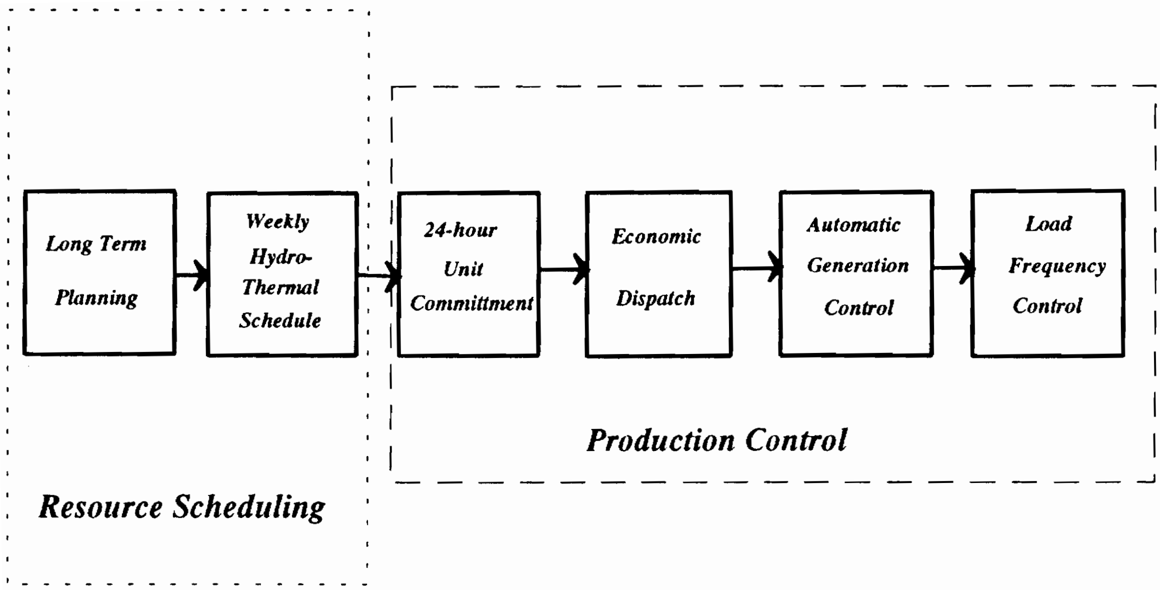


Figure 5.1 Functional Breakdown of the Operation Algorithm

5.1.1 PICES PACKAGE

The program consists of eight modules described below: This package ignores fuel and operating and maintenance costs. The input data includes unit availability, state forced outage rates, unit maximum capacity, maintenance time requirements (in weeks). Hydro and pumped storage hydro generation representation is a part of the program.

DEFAULT: This module sets default values for generating unit characteristics based on their plant type. The values include unit failure and repair rates based on data found in EEI's Report on equipment availability from 1968-1977, issued July 1979. However, this module is not used if actual values are input.

UNIFOR: This module calculates unit availability and state forced outage rates for 2 and 3 state unit models.

GENPRO: GENPRO calculates the exact generation capacity outage state probabilities and departures rates for the 2 and 3 state unit representations. The departure rates are calculated in units of (1/Day).

SCHED: The plant maintenance schedules are determined through this module based on the levelized reserve margin criteria. The plants are scheduled for maintenance in the order they are input to the data file.

DECON: DECON deconvolves any plants which are out on maintenance from the generation outage probability rate table on a weekly basis.

LDC: LDC calculates the weekly load duration curve.

LOFREQ: LOFREQ calculates the frequency of occurrence of the load on the load duration curve in units of (1 / week)

SYNFAD: This module calculates the probability, frequency, and duration of occurrence of cumulative reserve margin states having a magnitude less than or equal to user-defined level.

5.1.2 Case Study

The package is run in three variations. In the first case, the negative load concept is utilized, by which hourly PV power is subtracted from the hourly load. Second, the PV system is treated as generating unit, similar to any conventional power plant. In the third case, the equivalent conventional power is determined on the basis of LOLP comparison.

Virginia Tech Solar Test Facility (M55) system is used for this purpose. The availability and outage rates for the PV system are based on actual data. Table 5.1 displays the generator data used in this study. Table 5.2 lists the reliability summary for the three variations. Table 5.3 lists the weekly maintenance schedules for all plants.

Results in Tables 5.2 and 5.3 show that using the PV system as a generator increases the average reserve margin and decreases the annual LOLP compared to the negative load concept. The equivalent conventional plant has 575 MW rated capacity and high availability rate. The is equivalent to a 57.5 percent conventional generation displacement. Previous studies reported lower values. In Khallat [119], the ratio reached 18.2 for a 1000 MW PV system, using WASP. In Caramanis [120], the ratio was 27 percent for a 0.80 PV availability rate and 32 percent for a 0.91 availability, using EGEAS. The PV size was 780 MW and 638 MW, respectively. Finally, results presented here are based on 1-year planning period. However, the results presented by Khallat and Caramanis are based on a 10-year planning period. The high ratio in the present is due mainly to the high availability rate of VTSTF facility.

Table 5.1 Generator Data used in PICES

Unit No.	Unit Name	Unit Capacity (MW)	Maint Time (Week)	Unit Availability (%)	Unit Force Outage Rate (%)
1	NUC1	1200	7	0.8797	0.1203
2	NUC2	1000	7	0.8797	0.1203
3	NUC3	800	6	0.8797	0.1203
4	CSP1	1000	5	0.7714	0.2286
5	CSF1	800	5	0.7714	0.2286
6	CSP2	800	5	0.7714	0.2286
7	CSP3	800	5	0.7714	0.2286
8	CSBF	600	5	0.7624	0.2376
9	CSB1	600	5	0.7624	0.2376
10	CSB2	600	5	0.7624	0.2376
11	CSF2	600	5	0.7624	0.2376
12	CSB3	600	5	0.7624	0.2376
13	COSF	400	4	0.8481	0.1519
14	COSB	400	4	0.8481	0.1519
15	OIL1	800	5	0.7714	0.2286
16	OIL2	400	4	0.7723	0.2277
17	CTDF	120	2	0.8840	0.1160
18	CCNG	120	2	0.8840	0.1160
19	COSB	200	3	0.9028	0.0972
20	COSB	100	2	0.9028	0.0972
21	OIL2	200	3	0.9028	0.0972
22	OIL1	100	2	0.8840	0.1160
23	CT1C	100	2	0.8840	0.1160
24	COL5	50	2	0.8840	0.1160
25	OIL5	50	2	0.8840	0.1160
26	OLCT	50	2	0.8840	0.1160
27	CG50	50	2	0.8840	0.1160
28	CNG8	80	2	0.8840	0.1160
29	CG40	40	2	0.8840	0.1160
30	CTS5	50	2	0.8840	0.1160
31	CTDF	80	2	0.8840	0.1160
32	PS-HYDRO	500	2	0.9390	0.0610
33	HYDRO	1200	2	0.9842	0.0158
34	VTSTF[1]	1000	1	0.3333	0.6667
34	PVEQVT[2]	575	1	0.9524	0.0476

[1] Used in Variation 2 [2] Used in Variation 3

Table 5.2 Reliability Summary VTSTF PV Station for 1990

		Variation 1	Variation 2	Variation 3
Average Reserve Margin (%)	=	22.90	28.50	25.00
Average LOLP	=	0.0008391	0.0005550	0.0008454
Average Frequency	=	1.9000000	0.9000000	1.5000000
Average LOLE (Days)	=	0.306	0.202	0.308
Average Duration. (Hours)	=	3.970	5.570	5.100

Table 5.3 Weekly Maintenance Schedule VTSTF for 1990

Week	Variations (2&3)	Variation (1)
1-2	8 14 21	8 14
3	8 14 21	8 14 31
4	8 14	8 14 31
6-9	none	none
10	10 31	9
11	4 10 31	4 9
12	4 10	4 9
13-14	4 10 12	4 9 15
15	4 12	4 15
16-17	1 12	1 15
18-19	1 7 20 23 26 32	1 7 19 23 32
20	1 7	1 7 19
21-22	1 7 13	1 7 12
23	13 17 18 22 25	12 17 18 20 24 27
24	13 17 18 22 25 28	12 17 18 20 24 27
25	28	12
26-30	none	none
31	3 6 15	3 5
32-33	3 6 15	3 5 13 22 28
34-35	3 6 15	3 5 13 26
36	3	3
37	30 34*	29
38	30	29
39	none	none
40-43	2 9 16	2 10 16
44	2 9	2 10
45	2 19	2 21
46	2 11 19	2 11 21
47	11 19	11 21
48	5 11	6 11
49-50	5 11 24 29 33	6 11 25 33
51-52	5 27	6 30

*** 34 corresponds to VTSTF facility and PVEQVT facility used in Variations 2 and 3.**

Maintenance schedules are almost identical except for some units. In particular, nuclear power plants are scheduled for maintenance during the same week under both scenarios. Because the utility has two peaks, one in the winter and one in the summer, no maintenance activities are scheduled for weeks 6 through 9 and for weeks 26 through 30, respectively under both scenarios. The impact of these weekly maintenance schedules will be in the short-term system operations, namely the weekly hydro-thermal scheduling and the unit commitment as is discussed next.

5.2 Weekly Hydro-Thermal Scheduling

It is anticipated that hydro and pumped-storage hydro would play a major role in reducing problems associated with intermittent generation dynamics and load variations. This is due to their high ramping rates. In practice, the operator will schedule hydro power plants for few minutes as thermal generation is unable to fully absorb load variations and intermittent generation fluctuations. On the other hand, water availability is limited and minimum reservoir level must always exist throughout the week, it becomes necessary to schedule hydro generation on weekly basis. Similarly, energy transactions contracts with neighboring utilities and fuel delivery are done a weekly basis. These factors have direct impact on thermal generation schedule and on production control.

The weekly hydro-thermal scheduling is preferred over the daily one. In fact, in managing the reservoir, the further the dispatcher can look ahead into the week, the better the dispatch decisions will be. When operating on a weekly cycle, pumped storage plants start the week (Mondays in general) with a full reservoir. The plant is then scheduled over the weekdays to generate during high load periods and punp during low load periods. The reservoir is usually filled back to capacity by Sunday night. In some cases, the dispatcher might require a complete daily refill of the reservoir. In dispatching PS hydro, two questions would be answered. The first is whether to use daily or weekly scheduling. The second question is at what stage should the PSH power plant be dispatched, i.e. should PSH scheduling be done before or after accounting for PV output? The answer to the first question depends on whether the pumped-storage plant should operate to maximize pumped storage reserve capacity (security mode) or to minimize operating costs (economic mode). The second question needs a more detailed analysis and will be addressed.

The weekly hydro-thermal scheduling accounts for hydro availability, maintenance and repair schedules, and operating schedule for each unit. It also accounts for fuel availability and delivery, and power tie-line interchange with neighboring utilities. The weekly hydro-thermal algorithm uses data from the yearly generation planning. Its output includes hourly schedules for all units throughout the week. This is done by optimizing the hourly schedules based on the weekly load and PV forecasts. It also determines the start-up and shut-down schedules of all thermal units subject to minimum up-time and down-time, maintenance schedules, hydro availability and fuel availability.

While no much research has been done on the interactions between large-scale PV generation operation and weekly hydro-thermal scheduling, it was found it is worthwhile to study hydro scheduling, in particular pumped-storage hydro, with the presence of large PV systems. With this in mind, the main function of the proposed weekly hydro-thermal scheduling program is to coordinate pumped-storage generation with thermal generation by adopting the economic mode. Conventional hydro generation, on the other hand is dispatched on an average capacity basis throughout the week.

5.2.1 Pumped-Storage Hydro Optimization

Under mode (1), it is the function of the program to check the weekly load profile and determines the valley periods to schedule pumping. Under mode (2), the program finds the best times to schedule generation and pumping. While dispatching the pumped-storage hydro, the following operating constraints must be accounted for.

- *Generation/pumping constraints:* PS hydro plants have lower and upper generation levels and must pump at full capacity.
- *Generation ramping rate constraints:* PS hydro plants have limited ramping capabilities. The output can not change instantaneously. The ramping rate constraints are crucial in sub-hourly dispatching.
- *Reservoir constraints:* The amount of water which can be stored in the upper reservoir must be less than the reservoir size.
- *Initial and final reservoir levels:* The beginning and ending reservoir storage levels are specified by the dispatcher.
- *Charge and discharge rates:* PS hydro power plants have a minimum and maximum water discharge rates.
- *Pumping/generating cycles:* PS hydro power plants have a maximum number of pumping cycles per day.
- *Pumping/generating during weekends:* PS hydro power plants may not generate during low-load weekend periods, pumping may be advised instead.
- *Efficiency losses:* To account for losses in the pumping cycle, a cycle efficiency is used. The efficiency is sometimes imbedded in the water discharge rates.
- *O&M Costs:* When generating, PS hydro generation acquires constant O&M costs. When pumping, operating cost is included in the thermal generation cost.

In practice, baseload thermal generation is used to pump water back into the reservoir.

5.2.2 Pumped-Storage Hydro Scheduling Techniques

Several dispatching techniques were developed to optimize PS hydro utilization. These include pumped-storage hydro scheduling with λ-γ iteration, pumped-storage hydro scheduling by Gradient Method, incremental-decremental cost method, dynamic programming, multi-pass dynamic programming, linear programming, and based on load levels.

5.2.3 Formulating the Pumped-Storage Thermal Scheduling Solution

To optimize pumped storage utilization, one needs to find the lowest cost interval of the day to pump water and the highest cost interval to generate electricity. The idea is based on the incremental-decremental cost concept. The incremental cost λ_i is based on the highest average costs at time i, including combustion generation. Let λ_{max} and λ_{min} be the maximum and minimum average energy costs, respectively and λ'_{max} and λ'_{min} be the new maximum and minimum average energy costs, after accounting for pumping and generation efficiency. They are defined as follows:

$$\lambda'_{max} = \eta \times \lambda_{max} \tag{5.1}$$

and

$$\lambda'_{min} = \frac{\lambda_{min}}{\eta} \tag{5.2}$$

If λ_i ranges between λ'_{max} and λ_{max}, then the power plant will generate power. However, if λ_i ranges between λ'_{min} and λ_{min}, then water is pumped to reservoir. The procedure continues until all possible hours are scheduled either for charging or discharging water. At this point, the optimal pumping-generation schedule is obtained and cannot be optimized further. Figure 5.2 displays the flowchart of the proposed methodology.

5.2.4 Pumped-storage scheduling With PV System

The impact of PV presence on pumping and generation scheduling is investigated in this section. Two weeks, one in winter and one in summer, are considered. 34 units with a total capacity of 14,990 MW are used. The generating system, generation mix and fuel costs used are shown in Tables 5.4 and 5.5.

The pumped-storage technique is being tested for two weeks, one in winter (January 21 through 27), and one in summer (July 9 through 15). These two weeks were selected because they featured winter and summer load peaks. The winter peak load is 10,159 MW, and the summer peak load is 12,213 MW. The latter is also the annual peak load for the system. Each week started with full reservoir. The round-trip efficiency for the hydro plant was set at 0.80. The pumping and generating capacities were set at 500 MW and 400 MW, respectively. Richmond actual PV power output were also used. The PV system is rated at 2000 MW. Figures 5.3 and 5.4 display system performance for the two weeks, while Tables 5.6 and 5.7 display changes in system performance due to PV system scheduling for the weeks. Production cost and generation requirement changes for using PV system are also shown in the bottom table. Negative numbers mean savings.

In the upper part of each figure, reference load means system demand plus losses. Load (w/o PV) means reference load plus pumping requirements, without PV system. Load (with PV) refers to reference load plus pumping requirements with the PV system integrated. The lower part display pumping/generation and water reservoir level throughout the week. The reservoir is 100 percent full at the beginning week. In Figure 5.3, PV presence did not change pumping/generation schedule, except for the one hour shift in day six, (hour 128). However, for the July week (Figure 5.4), the pumping and generation schedule changed significantly during the first four days. The change involved the length of pumping and generation periods. For example, in day one (Figure 5.4), less generation was scheduled during peak load period and less pumping was recorded during the valley period. This was due to good PV power output for the day. Similarly for days 2 through 4 less pumping and generation activities were recorded. However, no additional pumping/generation activity was recorded during the weekend.

The change in pumping and generation schedule was due to good match between the peak load and peak PV power output and good PV system energy performance throughout the week of July. The cumulative production cost savings with pumped storage and PV system were $,1946,864 and $2,661,824 for January and July. The total production cost savings with PV system only reached $1,262,432 and $2,616,256 for January and July, respectively. With pumped-storage, the savings due to PV generation were $1,271,168, $ 2,592,432, respectively. This means an increase of $8,736 for January and decrease of $23,824 for July. For the week of January, the PV Energy Values (PVEV), defined below, are 9.80 mils/kWh and 9.89 mils/kWh without and with pumped storage hydro. For July, PV energy values are 13.35 mils/kWh and 13.22 mils/kWh, respectively. Here PVEV is the PV energy value is the ratio of total production cost savings to the maximum energy produced by the PV system during sunshine hour. It is defined by:

$$\text{PVEV (mils / kWh)} = \frac{(\text{Production Cost Savings})}{(\text{PV Size} \times \text{Daylight Hours})} \qquad (5.3)$$

where

• PV size is the PV installed capacity, in (MW);

- Production cost savings is in ($); and
- Daylight hours is the average sunshine time (hours) for the month.

The PV energy value decrease in the week of July is due to lower combustion turbine and tie-line generation reduction in the pumped-storage case. Without pumped-storage, PV system displaced 13,380 MWh of CT generation and 2777 MWh of tie-line energy. However, with pumped-storage, PV system displaced only 12,490 MWh, and 85 MWh, respectively. Both types of generation have high energy costs (see Table 5.5).

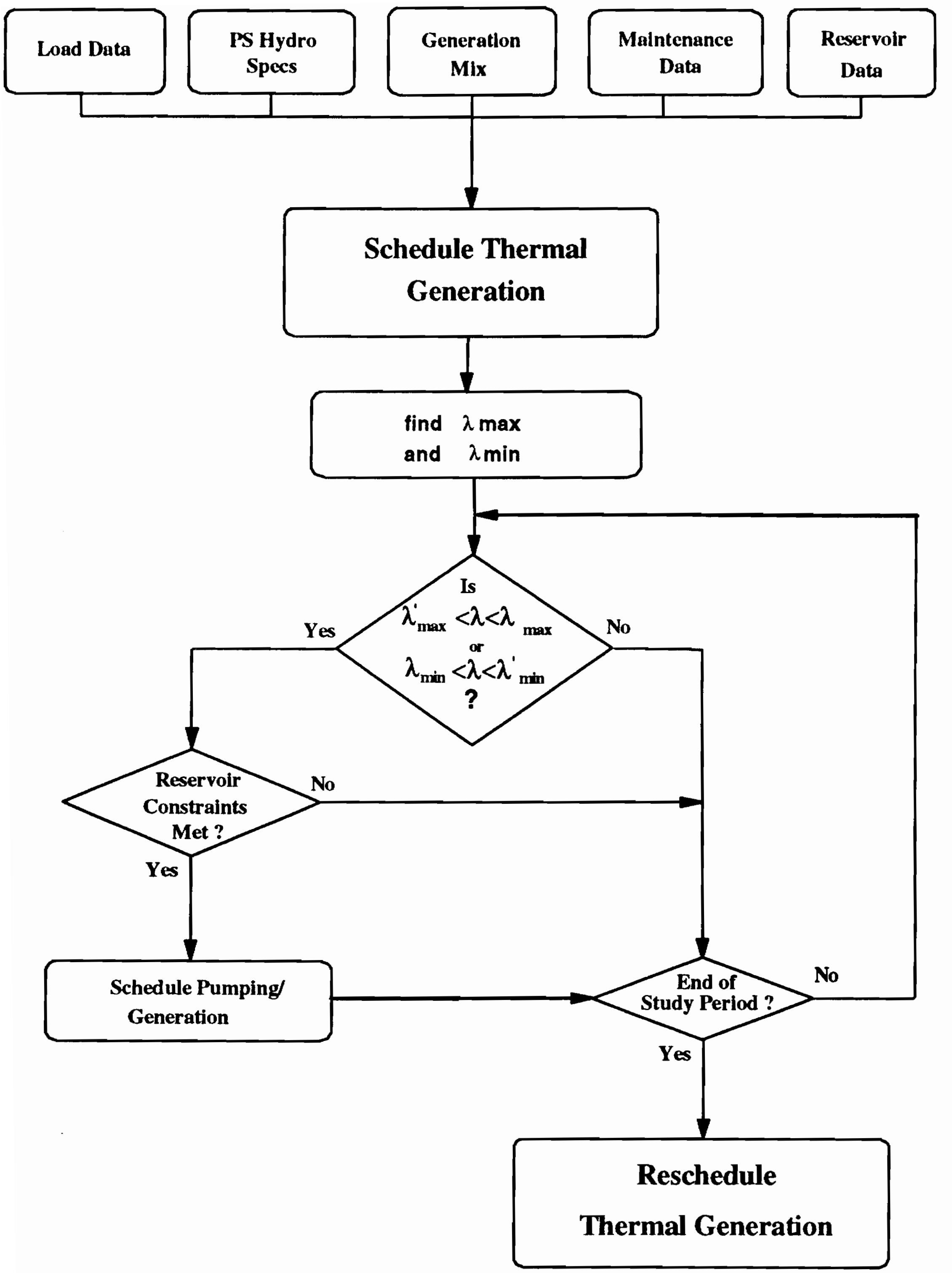


Figure 5.2 Flow Chart of the Pumped-Storage Hydro and Thermal Optimization

Table 5.4. Synthetic Generation System

Unit No.	Unit Name	Capacity max (MW)	Capacity min (MW)	Heat Rate Coefficient A	B	C (x1000)	Minimum down (hours)	Minimum up (hours)	Startup Cost ($)	Ramp Rate min (%/min)	Ramp Rate max (%/min)
1	Nuclear-1	1200	360	1800.00	6.550	1.833	24	24	6000	0.5	2.5
2	Nuclear-2	1000	300	1150.00	6.550	0.220	24	24	6000	0.5	2.5
3	Nuclear-3	800	300	1320.00	6.550	2.750	24	24	6000	0.5	2.5
4	Coal-1	1000	300	990.00	7.536	0.480	24	24	736	0.5	2.5
5-7	Coal-2	800	280	804.00	7.891	0.625	24	24	736	0.5	2.5
8	Coal-5	600	200	710.43	7.352	2.022	24	24	736	0.5	2.5
9-12	Coal-6	600	200	699.15	7.001	1.988	24	24	736	0.5	2.5
13	Coal-10	400	100	469.50	7.397	2.950	8	8	533	0.5	2.5
14	Coal-11	400	100	462.00	7.046	2.900	8	8	506	0.5	2.5
15	Oil-1	800	280	906.75	6.746	1.444	8	8	737	0.5	4.0
16	Oil-2	400	100	468.05	7.049	2.951	8	8	300	0.5	4.0
17	Gas-1	120	40	203.40	5.368				100	1.0	4.0
18	Gas-2	120	40	203.62	5.697				100	1.0	4.0
19	Coal-12	200	50	244.12	7.425	6.150	8	8	422	0.5	4.0
20	Coal-13	100	25	140.90	8.632	14.050	8	8	422	0.5	4.0
21	Oil-3	200	0	233.25	7.779				100	1.0	4.0
22	Oil-4	100	0	144.28	8.587				100	1.0	4.0
23	Gas-3	100	0	269.00	9.010				100	1.0	4.0
24	Gas-4	50	0	58.92	12.459				100	1.0	4.0
25	Oil-5	50	0	58.92	12.459				100	1.0	4.0
26	Oil-6	50	0	101.82	10.596				100	1.0	4.0
27	Gas-5	50	0	69.67	14.727				100	1.0	4.0
28	Gas-7	80	0	248.80	9.074				100	1.0	4.0
29	Gas-8	40	0	128.90	9.402				100	1.0	4.0
30	Oil-7	50	0	86.12	7.426				100	1.0	4.0
31	Oil-8	80	0	240.20	8.761				100	1.0	4.0
32	PS Hydro	500	0						100	10.0	100
33	Hydro	1200	0						100	10.0	100
34	Tie-line	500	0								

Source: [38-41]

Table 5.5 Energy Costs and O&M Costs

Technology	Generation (MW)	Mix (%)	Energy Costs (¢/kWh)
Nuclear	3000	20.00	3.10
Coal	7500	50.00	4.30
Steam Oil	1200	8.00	5.30
Oil (CT)	530	3.55	8.10
Natural Gas (CT)	560	3.75	6.70
Hydro	1200	8.00	0.20
Tie-line Interchange	500	3.35	5.00
PS Hydro	500	3.35	3.50
Total	14990	100.00	**Source [124]**

* Based on the smallest unit and minimum loading
**Based on the smallest unit and at 50% loading
PV O&M costs are 5 mills/kWh [36]

Table 5.6 System Performance Summary with and without PV, January 21-27

(Total PV Generation = 29,542 MWh)

PSH	load (MWh)	CT Gen. (MWh)	Disp. Gen. (MWh)	PSH Gen. (MWh)	PSH Pumping (MWh)	Tie-Line Energy (MWh)	Startup Cost ($)	Prod. Cost ($)	Energy cost (mils/kWh)
No	1157192	1120	1156129	0	0	0	9423	47 191 872	40.78
Yes	1157905	1120	1146543	20800	10500	0	8339	46 516 176	40.17
	with	**PV**	**System**						
No	1126256	1120	1125192	0	0	0	10387	45 929 440	40.78
Yes	1127027	1120	1115655	20800	10500	0	8689	45 245 008	40.15
	Difference								
No	-30836	0	-30937	0	0	0	964	-1 262 432	0
Yes	-30878	0	-30888	0	0	0	350	-1 271 168	-0.02

Table 5.7 System Performance Summary with and without PV, July 9-15

(Total PV Energy = 48,136 MWh)

PSH	load (MWh)	CT Gen. (MWh)	Disp. Gen. (MWh)	PSH Gen. (MWh)	PSH Pumping (MWh)	Tie-Line Energy (MWh)	Startup Cost ($)	Prod. Cost ($)	Energy cost (mils/kWh)
No	1487237	35110	1452156	0	0	3291	19816	59 723 328	40.16
Yes	1487659	33620	1453673	8400	8000	154	19485	59 653 936	40.10
	with	**PV**	**System**						
No	1435095	21730	1413393	0	0	1014	18868	57 107 072	39.79
Yes	1435272	21130	1413958	3200	3000	69	19103	57 061 504	39.76
	Difference								
No	-52142	-13380	-38763	0	-5000	-2777	-948	**-2 616 256**	-0.37
Yes	-52387	-12490	-39715	-5200	-5000	-85	-382	**-2 592 432**	-0.34

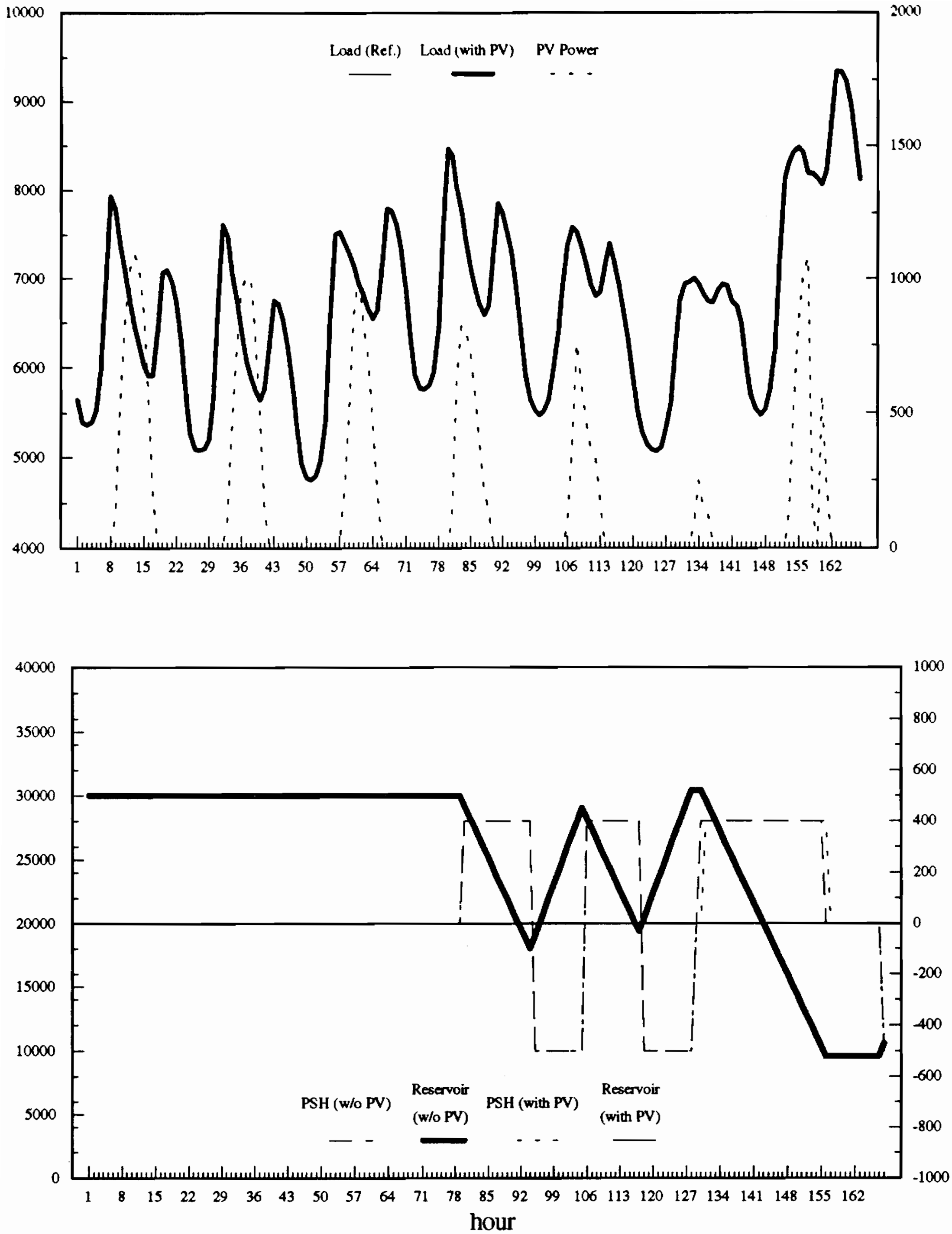


Figure 5.3 Pumped-storage coordination with and without PV, January week

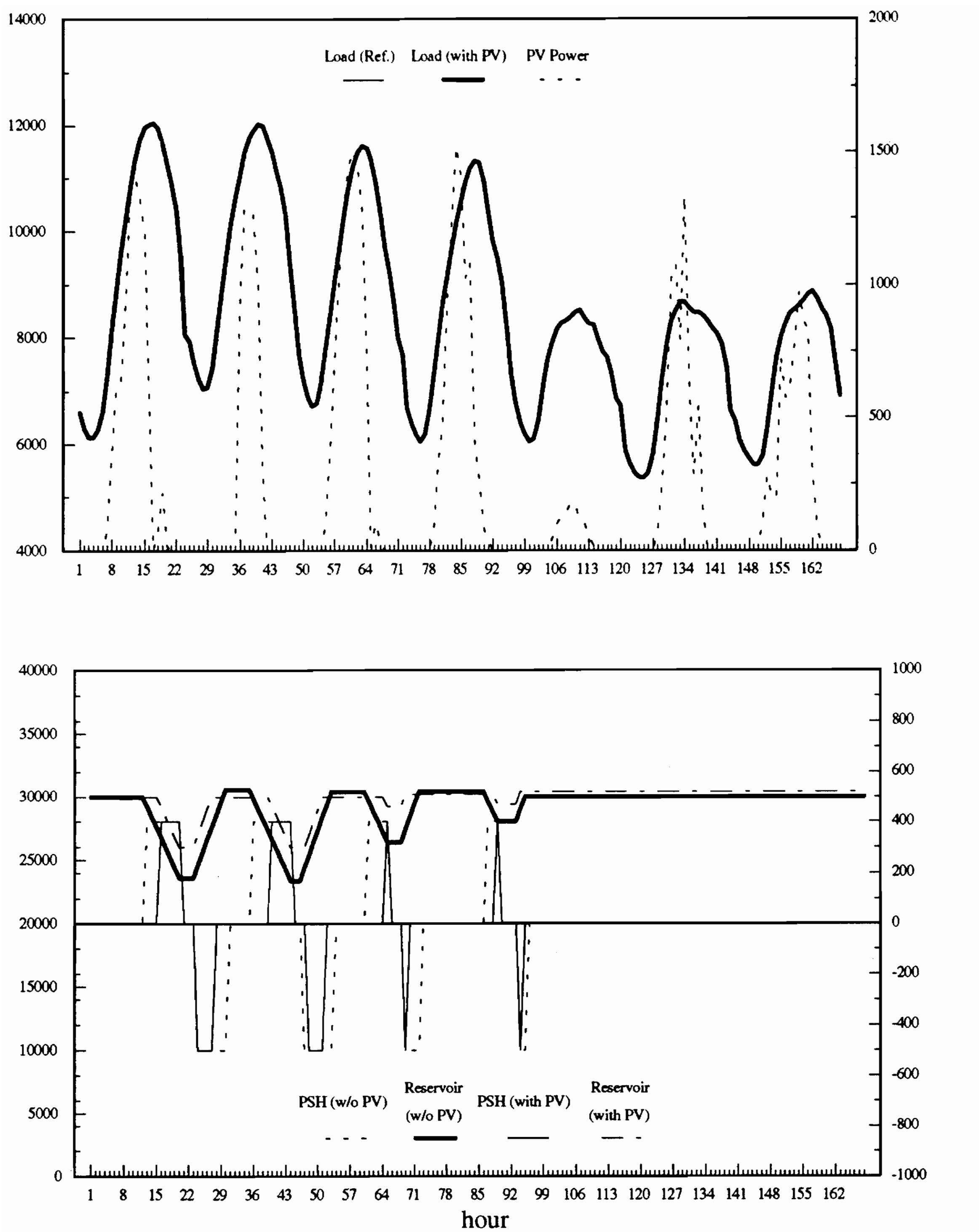


Figure 5.4 Pumped-storage coordination with and without PV, July week

5.3 Unit Commitment

Unit commitment is the process of selecting a combination of generating units that will supply system load over a required period of time, usually 24 hours to 168 hours, at minimum cost as well as provide specified margin of spinning reserves. The determination of the units to be operated in a given interval depends on their operating costs as well as technical merits. While the operating cost consists of fuel and maintenance costs, the technical merits include stability limitations, fuel scheduling and delivery, and contracts with neighboring electric utilities.

In general, generating units can be classified into three groups, thermal, hydro, and renewable. The operation of thermal units involves both fuel and maintenance costs, that of hydro units involves operation and maintenance costs and water displacement. Renewable energy sources operation involves operating and maintenance costs. Thermal units include conventional steam plants, nuclear plants, and diesel and gas turbines. Hydro plants include conventional hydro and pumped-storage hydro plants. Renewable energy systems include wind energy conversion systems, solar photovoltaic and geothermal systems. Unit commitment is a part of the production control scheme in power systems. The main objective of production control is to minimize the cost of generated while maintaining adequate levels of quality and security. This implies minimum losses at the generation and transmission levels and adequate spinning reserve margins. In particular, the 24-hour unit commitment finds hourly commitment schedule for the anticipated load and resource forecast and maintenance schedule for the day. It would account for the effect of hourly load and PV output fluctuations subject to constraints.

5.3.1 Solving the Unit Commitment Problem

At present, unit commitment algorithms consider the following constraints:

- Initial unit operating conditions. large units would not be turned on or off at the beginning of the 24 hour period.
- Unit minimum and maximum capacity. Capacity limits may change frequently due to maintenance of unscheduled outages of various equipment in the plant.
- Unit minimum up-time. Once the unit is running, it should not be turned off immediately.
- Unit minimum down-time. Once the unit is decommitted, it requires minimum time before it can be recommitted.
- Unit startup and shutdown costs. Once a unit is decommitted, it requires maintenance, cooling and banking cost before the unit is brought into the unit commitment problem.
- Crew constraints. If a plant consists of two or more units, they cannot both be turned at the same time. This constraint is not active in most cases.
- Must-run and must-out constraints. Some units are given either status for reason of voltage support or supply of fuel.
- Fuel constraints. Some units have limited fuel supply and delivery.
- Spinning reserve constraints. Spinning reserve must be carried so that the loss of one or more units does not disturb the system and deteriorate the reliability.
- Unit response rates. Once a unit is committed or decommitted, it cannot change its output instantly. This include boiler cooling time, and minimum up-time and minimum down-time
- Hydro availability. In addition to the above constraints, the hydro-thermal unit commitment takes into account hydro availability for two reason, one is related to the rain fall for the season and the other involves hourly water availability distribution. Two benefits results from adopting a such approach. First, the

daily water allowances are never exceeded. Second, the water usage is controlled by the demand requirements. Such requirements are function of thermal generation resources and intermittent generation performance. The benefit is more significant when the intermittent generation is very fluctuating, therefore, the economic dispatch solution includes the constrained hydro dispatchability.

To solve the unit commitment problem, several solution techniques exist. These include partial enumeration, dynamic programming, Benders partitioning, priority listing scheme, Lagrangian relaxation, mixed integer-linear programming, heuristics (rule-based), and expert systems methods. Of these methods, the priority listing scheme is the most popular. The specific program used is the "Unit Commitment and Production Costing Program EGUPC" developed by Boeing Computer Services for the Electric Power Research Institute, EPRI [10, 11]. Details of the program and program modifications are given below.

5.3.2 EPRI's Unit Commitment Program

The program is designed to analyze the operations of generation and transmission systems consisting primarily of thermal committable generating units and with possible additional capacity in the form of non-committable combustion turbines, pumped-storage hydro, hydro and tie-line interchange. Its main function is to schedule generation and interchange on a hourly basis for periods ranging from 24 hours to 168 hours. Given the profile of the expected hourly loads, generation mix, and maintenance schedule, the program generates a unit commitment schedule such that the expected system load is met at suitably low cost under various operating constraints. Once a schedule has been obtained, the total costs are estimated. The program also monitors fuel consumption by each generating plant, station and fuel type and gives a warning if the fuel maximum supply is violated. However, both water availability and fuel supply constraints are not active. In addition, non-committable units are scheduled without regard to their fuel energy costs. Hydro and pumped-storage hydro units are scheduled without respect to water availability and most economical manner. Therefore, modifications were introduced on the program to account for these constraints. These modifications will be described later. First, the scheduling processes used by the program is highlighted. The need to describe these processes and modifications stems from the proposed economic dispatch and automatic generation control programs described in later chapter.

5.3.2.1 Input Data

The input data required by the program consists of:

- processing options such as spinning reserve requirements, priority list generation options.
- load specification option, convergence criteria, etc..
- generation mix identification. This includes cost and performance data, such as unit name, fuel type, heat rate, startup time and cost, minimum uptime and minimum downtime, boiler cool time, etc..
- load models for up to a week.
- manual maintenance and operation schedules for all units.
- transmission loss data and option.

5.3.2.2 Priority List Generation

Commitment of dispatchable units proceeds on the basis of a single priority list which may be provided by the user or generated by the program. The priority list generation is based on the operating cost and capacity of the unit. The process stops when the capacity of the reduced unit set is a specified fraction of the total generation capacity. The units remaining in the set are then assigned priorities based on the relative operating costs at their maximum capacity.

5.3.2.3 Combustion Turbine Priority List Generation

The is able to read the priority list as requested by the user. The list is expected to change as fuel costs varies and operating capacity might change. The proposed priority list generation for combustion turbines is based on the fuel cost, heat rate and full capacity. Unit with highest operating cost, has the lowest priority index. Unit with lowest index is committed first and decimated last.

5.3.2.4 Precommitment of Peaking Units

The function of this process is to schedule combustion turbines and tie-line interchange on a hourly basis for three purposes. The first is to provide sufficient on-line generating capacity and interchange to meet the anticipated load plus losses. The second is maintain adequate levels of capacity and interchange to meet load plus losses and reserve requirements. The third is to cycle off more expensive thermal units, as requested by the user.

5.3.2.5 Hourly Generation Maximum Capacity

The hourly maximum generation capacity is the sum of maximum capacities of all on-line committable units, the maximum capacities of any combustion turbines, as specified by the user, and user-scheduled tie-line interchange and hydro capacity.

5.3.2.6 Reserve Capacity from Non-Committable Sources

All non-committable sources contributes to two types of reserves (ten-minute and spinning reserves) as function of the unit type and status during each hour. The reserve capacity from non-committable sources is required in order to compute the ten-minute and spinning reserve capacity from these sources and to estimate the additional reserve capacity required from committable sources.

5.3.2.7 Hourly Regulation Requirement

The program attempts to provide sufficient regulating margin during periods of load pickup by providing enough "system response rate" sufficient to meet the load increase for the next hour. This capacity is equal to the additional on-line dispatchable generation capacity. Part of the this capacity is used as spinning reserve.

5.3.2.8 Committable Unit Commitment Schedule

The dispatchable unit commitment schedule is basically obtained by considering a shutdown decision for each unit on a hour by hour basis. The default status of all dispatchable units is the Economic Run Status. Then at every hour a decision is made whether to shut down the unit or not. First, this decision is based on whether the load plus losses, reserve and regulation requirements up to its minimum down time are satisfied or not. Second, an economic comparison is performed. This is done by prorating the unit's startup cost over the shutdown period and the up time. A comparison of an hour's fuel costs plus prorated value of start-up costs will allow the determination of the most economical set of on-line generators. The hourly start-up costs are monitored and passed to the sub-hourly economic dispatch program.

Once the schedule of non-committable units has been determined, an hourly economic dispatch is performed to determine the dispatchable generation schedule, taking into account the minimum downtime and minimum running time, startup costs, and hydro availability. The contribution of this dissertation was to make hydro dispatching a part of the hourly economic dispatch, since the levels of generation of all units determine which units much be committed to meet load and spinning reserve requirements. Following is a description of the proposed unit commitment with hydro.

5.3.3 Hydro Constrained Unit Commitment

Today, with the increasing importance of intermittent generation sources, in particular PV and wind energy systems, interrelationships among various of electric power sources become more complex and the study of their effects on intermittent generation deems necessary. While PV systems are expected to increase available spinning reserves and reduce fuel consumption, O&M costs, and water usage, their optimal operational and economical values are not fully determined yet.

5.3.3.1 Formulating the Unit Commitment Problem

The cost FC_i of operating a unit i may be expressed as the product of fuel cost $fcst_i$ and heat rate HR_i :

$$FC_{it} = fcst_i \times HR_{it}$$

$$FC_{it} = fcst_i \times (a_i + b_i P_{it} + c_i P_{it}^2) \quad (\$ / hr) \qquad (5.4)$$

for a hydroelectric, pumped-storage hydro, photovoltaic, and wind energy systems, operating costs are composed of O&M costs.

The water discharge rate $q_j(P_{jt})$ of hydro unit j during interval t, is given by:

$$q_{jt}(P_{jt}) = (d_j + e_j P_{jt} + f_j P_{jt}^2) \quad (acre-feet / hr) \qquad (5.5)$$

Now consider a system with N_{th} thermal plants and N_h hydro plants operating essentially at constant head. Then the total cost F_t of generation at time t is given by:

$$F_t = \sum_{i=1}^{N_{th}} F_i(P_{it}) + \sum_{j=1}^{N_h} F_j(P_{jt}) \quad (\$ / hr) \qquad (5.6)$$

It is desired to minimize the total fuel cost TF over the entire scheduling period.

$$TF = \sum_{t=1}^{T} F_t \quad (\$) \tag{5.7}$$

where T is the number of periods in the scheduling periods.

The minimization is carried out such that:

i) The total system generation matches the power demand D_t and system losses Tl_t, that is for time t:

$$\sum_{i=1}^{N_{th}} P_{it} + \sum_{j=1}^{N_h} P_{jt} = D_t + \mathrm{Tl}_t \tag{5.8}$$

Tl_t is given by:

$$\mathrm{Tl}_t = K_{lo} + \sum_{k=1}^{N_{th}+N_h} B_{ko} P_{kt} + \sum_{k=1}^{N_{th}+N_h} \sum_{i=1}^{N_{th}+N_h} P_{kt} B_{ki} P_{it} \tag{5.9}$$

where

P_{it} and P_{kt} are source loadings at time t, and

B_{ki} are the transmission loss formula coefficients.

ii) A certain amount of available power must be kept which can be quickly mobilized in few minutes to deal with unexpected unit breakdown or unavailability, increase in load, drop in intermittent power output, etc. This available power is termed spinning reserve and can be supplied by on-line units. Minimum spinning reserve at time t, SR_t must always exit, i.e.,

$$\sum_{i=1}^{N_{th}} (P_{it}^{\max} - P_{it}) + \sum_{j=1}^{N_h} (P_{jt}^{\max} - P_{jt}) \geq SR_t \tag{5.10}$$

iii) The amount of water available for discharge for each hydro plant j must not exceed a well defined level B_j, a function of rain fall, seasonal variations and other considerations. That is:

$$\sum_{t=1}^{T} q_{jt}(P_{jt}) \leq B_j \qquad (5.11)$$

iv) Thermal and hydro power plant capacity limits,

$$\text{i.e.,}\quad P_l^{min} \leq P_{lt} \leq P_l^{max} \qquad (5.12)$$

$$\text{for } l = 1,2,\ldots,N_{th} \quad \text{and } l = 1,2,\ldots,N_h$$

vi) Other constraints include water discharge limit, emission allowances, fuel consumption rates and allowances, reactive power requirements, unit minimum down time and up time, and ramping rates.

5.3.3.2 Solving the Unit Commitment Problem

The forth mentioned economic dispatch problem can be solved using non-linear optimization techniques. Among these are the penalty methods, gradient projection, Lagrangian methods, direct search, and recently, heuristics. The Lagrangian method is considered in this study. Without loss of generality , only load, spinning reserve, and maximum water discharge constraints are considered in the solution.

The augmented cost function L is given by:

$$\begin{aligned}
&L(P_{it}, P_{jt}, \lambda_t, \mu_t, \gamma_j) \\
&= \sum_{t=1}^{T} \{ \sum_{i=1}^{N_{th}} F_i(P_{it}) + \lambda_t [D_t + Tl_t - \sum_{i=1}^{N_{th}} P_{it} - \sum_{j=1}^{N_h} P_{jt}] \\
&+ \mu_t [\sum_{i=1}^{N_{th}} (P_{it}^{max} - P_{it}) + \sum_{j=1}^{N_h} (P_{jt}^{max} - P_{jt}) - SR_t] \ \} \qquad (5.13) \\
&+ \sum_{t=1}^{T} \sum_{j=1}^{N_h} \gamma_j [q_{jt}(P_{jt}) - B_j]
\end{aligned}$$

where

P_{it}^{min} and P_{jt}^{max} are the lower and upper capacity limits.

Optimality Conditions

The optimality conditions are made up of two sets. The first is the problem constraints:

1-a) The power balance equation should be satisfied at each time step.

1-b) The spinning reserve balance equation should be satisfied at each time step.

1-c) The daily volume of water constraints should be satisfied at each hydro plant.

The second set is based on variational arguments, this means that the derivative of L with respect to P, λ, μ, and γ must equal zero.

$$\frac{\partial L}{\partial P_{it}} = \frac{\partial L}{\partial P_{jt}} = \frac{\partial L}{\partial \lambda_t} = \frac{\partial L}{\partial_{\mu t}} = \frac{\partial L}{\partial \gamma_j} = 0 \qquad (5.14)$$

That is:

2-a) for each thermal unit i,

$$\frac{dF_i(P_{it})}{dP_{it}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{it}} - 1) - \mu_t = 0 \qquad (5.15)$$

2-b) for each hydro unit j,

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}} - 1) - \mu_t = 0 \qquad (5.16)$$

Rearranging 5.15 and 5.16 yields the famous hydro-thermal coordination equations:

$$\frac{dF_{it}(P_{it})}{dP_{it}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t + \mu_t \qquad \text{for } i = 1,2,\ldots,N_{th}$$

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t + \mu \qquad \text{for } j = 1,2,\ldots,N_h \qquad (5.17)$$

These two equations along with the capacity limits, power and demand balance, spinning reserve balance, and other physical constraints constitute a set of non-linear equations that are time dependent and require iterative methods to solve.

Interpretation

The energy price λ_t and the spinning reserve price μ_t (both in \$/MWh) would be adjusted so that system load plus losses and spinning reserve requirements are mutually satisfied.

γ is defined as the incremental water value (\$/MW) and depends on generation mix, fuel costs and daily energy requirements. It gives an indication of how to achieve minimum fuel cost without violating maximum water allowances.

The optimality conditions require equal penalized incremental fuel cost (thermal), and penalized incremental rate of water discharge.

Alternative Solution

To reduce the complexity of the problem, the following modifications are made. The spinning reserve balance can be rewritten as:

$$\sum_{i=1}^{N_{th}} P_{it}^{\max} + \sum_{j=1}^{N_h} P_{jt}^{\max} \geq D_t + Tl_t + SR_t \qquad (5.18)$$

The new Lagrangian function and coordination equations are:

$$L(P_{it}, P_{jt}, \lambda_t, \mu_t, \gamma_j)$$
$$= \sum_{t=1}^{T} \{ \sum_{i=1}^{N_{th}} F_i(P_{it}) + \lambda_t [D_t + Tl_t - \sum_{i=1}^{N_{th}} P_{it} - \sum_{j=1}^{N_h} P_{jt}] \tag{5.19}$$
$$+ \mu_t [\sum_{i=1}^{N_{th}} P_{it}^{\max} + \sum_{j=1}^{N_h} P_{jt}^{\max} - (D_t + Tl_t + SR_t] \}$$
$$+ \sum_{t=1}^{T} \sum_{j=1}^{N_h} \gamma_j [q_{jt}(P_{jt}) - B_j]$$

and

$$\frac{dF_{it}(P_{it})}{dP_{it}} + (\lambda_t - \mu_t) \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t \qquad \text{for } i = 1, 2, \ldots, N_{th}$$
$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + (\lambda_t - \mu_t) \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t \qquad \text{for } j = 1, 2, \ldots, N_h \tag{5.20}$$

respectively. Moreover, adequate spinning reserves are provided by the regulating margin capacity.

$$REQ_t = [D_{t+1} - D_t] \times GENMIN + PND_t - PND_{t+1}$$
and
$$DISREG_{t+1} = REGFAC \times REQ_t \qquad \text{for } REQ_t \rhd 0 \tag{5.21}$$
and
$$DISREG_{t+1} = 0 \quad \text{otherwise}$$

where

$D_t(t)$	=	the load for hour t
PND_t	=	the total non-committable generation for hour t
$DISREG_t$	=	the regulation requirements for hour t, and
REGFAC	=	a user-input regulation factor.

5.3.3.3 Proposed Unit Commitment Solution

For the purpose of this study, the following assumptions are made:

- Transmission losses are included in the hourly economic dispatch solution. The coordination equation can be rewritten as:

$$\frac{dF_{it}(P_{it})}{dP_{it}} + (l_t)\times(\frac{\partial Tl_t}{\partial P_{jt}}) = l_t \qquad \text{for } i = 1,2,\ldots,N_{th}$$
$$g_j\frac{dq_j(P_{jt})}{dP_{jt}} + (l_t)\times(\frac{\partial Tl_t}{\partial P_{jt}}) = l_t \qquad \text{for } j = 1,2,\ldots,N_h \qquad (5.22)$$

- The total startup cost for the day is the sum of dispatchable generation startup costs and combustion turbines startup costs incurred by the economic dispatch. Figure 5.4 displays the proposed λ-γ iteration scheme.

The initial value for incremental cost λ is determined based on the average fuel cost. However, may not converge because of capacity constraints. For this reason, λ must be adjusted until the load and losses requirements are met. An updated estimate of λ is provided using an interpolation process based on past estimates and their resulting generation and load plus losses.

Procedure

In the first update, the value of λ is incremented by $\Delta\lambda$ and defined below. For more details, please refer to references 10 and 11.

$$\Delta\lambda = \lambda\times(\frac{xload}{TGen - Tloss} - 1.)/2. \qquad (5.23)$$

where

xload is the load to be dispatched,

PGen is the total generation, and

Tloss is the total system losses.

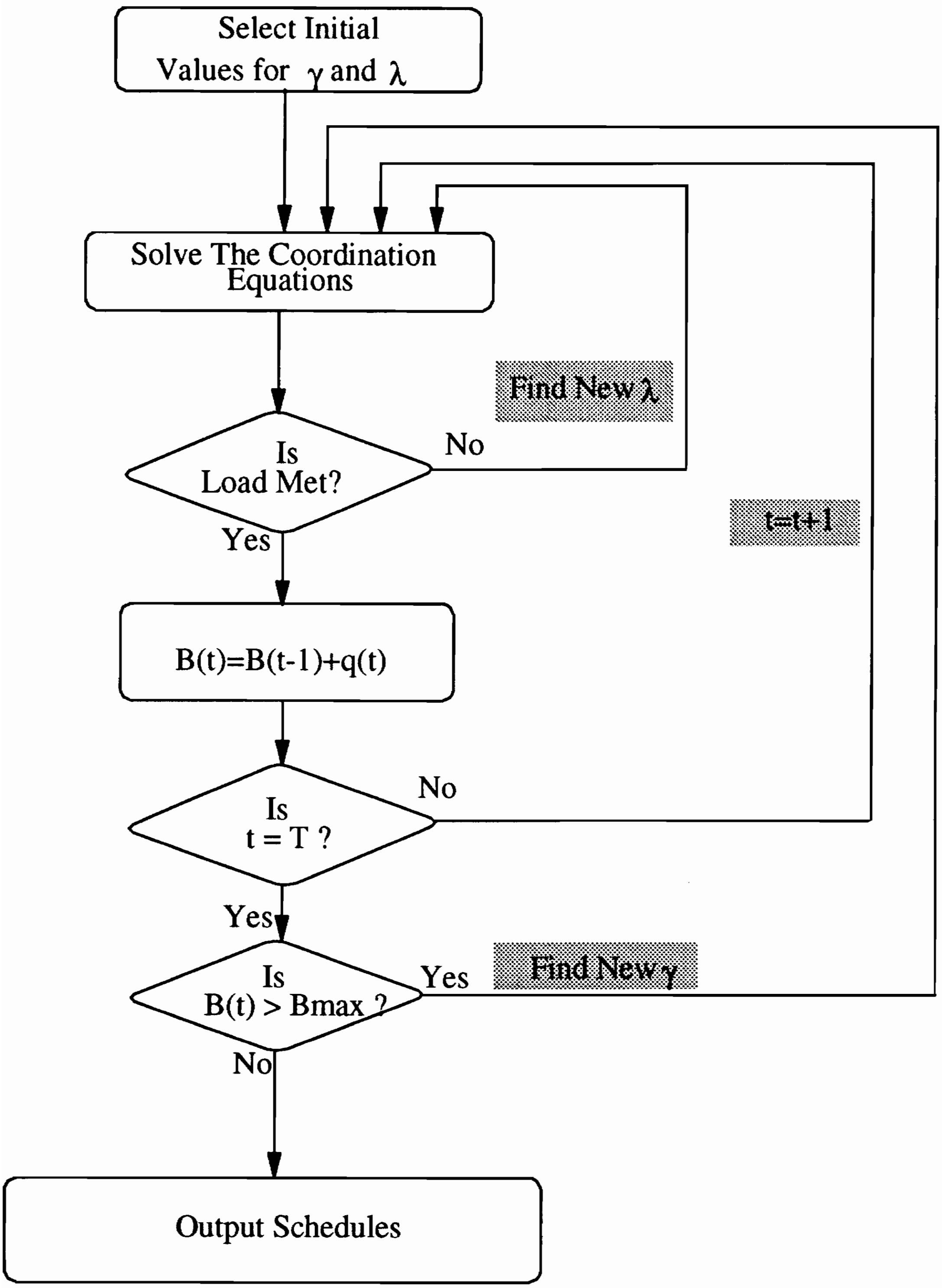


Figure 5.4 Proposed λ−γ Iteration Scheme

If this is not the first iteration, then λ is updated by $\Delta\lambda$ by interpolating between the current estimate and the last estimate on the opposite side of the target. $\Delta\lambda$ is defined by:

$$\Delta\lambda = (\frac{\lambda \ \ - \lambda_+}{\Delta G_+ - \Delta G}) \times \Delta G \quad \text{for}\, \Delta G \lhd 0$$
$$\Delta\lambda = (\frac{\lambda \ \ - \lambda_-}{\Delta G_- - \Delta G}) \times \Delta G \quad \text{for}\, \Delta G \rhd 0 \qquad (5.24)$$

where

ΔG is the total difference between total generation and load plus losses,

ΔG_+ is the value ΔG as of last estimate of λ that was too high,

ΔG_- is the value ΔG as of last estimate of λ that was too low,

λ_+ is the value of λ estimate as of the last iteration in which λ was too small, and

λ_- is the value of λ estimate as of the last iteration in which λ was too high.

The initial value of λ at time t+1 is the final estimate of λ for time t.

5.3.3.4 Hydro Dispatching

For each time t, the value of γ_j is adjusted to reflect the load variation using the following model. The new value γ_{jt} is obtained:

$$\gamma_{jt} = \gamma_j \times \exp(-1. + \frac{\text{xload}}{\text{Peak Load}}) \qquad (5.25)$$

where

• et Peak Load is the peak dispatchable load to be served by the hydro and baseload thermal generation.

• load is the dispatchable load at time t, and

• V_t is the PV power output at time t.

During the model development, it was found that the optimal value of γ needs to be adjusted to satisfy maximum water availability for each 24 hour period. For this reason, the following iterative process was suggested. The parameters of the model were found through simulations using actual load, generation mix and fuel cost data. Further tuning was needed to account for optimal solution convergence. These parameters are a function of the fuel costs, generation mix, and load requirements. The following model was used for a given hydro power plant. It is based on the sub-gradiant search method.

$$\gamma_{n+1} = \gamma_n - \frac{\alpha}{\beta} \times (1+n) \times (B_{max} - B_n) \tag{5.26}$$

where

- γ_{n+1} and γ_n are the new and old estimates of γ at iterations n+1 and n, respectively.
- α is a tuning parameter, its value ranges from 0.1 to 0.2,
- β is a tuning parameter. A typical value is the peak load for the day,
- B_{max} is the maximum water allowance for the day , and
- B_n is the total water discharge for the day at iteration n based on γ_n.
- The convergence criteria is $|B_{n+1}-B_n| \leq 0.01 \times B_{max}$.

First, the number of iterations depends heavily on the initial value of γ, the step increment and convergence criteria. If too low or too high initial value is used, the number of iterations increases significantly. For example, a part of the study was to assess the breakeven capital of PV system. The study consists of several scenarios. To reduce computing time, most recent values of γ were used for subsequent scenarios. Variations of γ and B shown in Figures 5.5 and 5.6 for peak load days in January 28 and July 10. The initial values for γ is 1. The peak loads for these two days are 10,058 and 12,030 MW, respectively. The operation summary is listed in Tables 5.8 and 5.9. Figures 5.7 and

5.8 show hourly system performance for the two days. The upper portion of each figure displays hourly load, dispatchable generation, and spinning reserves on the left axis, and hourly production cost on the right axis. The lower portion displays hourly combustion, hydro, pumped storage pumping and generation and tie-line interchange. On January 28, no pumping activities were scheduled. For July 10, pumping was scheduled between 12:00 a.m. and 8:00 a.m. between 10:00 and 11:00 a.m., and between 10:00 p.m. and 12:00 a.m.. The pumping/generation schedules were mandated by the weekly pumped storage coordination.

In this chapter, yearly planning, weekly pumped-storage scheduling, and unit commitment with constrained hydro dispatch have been discussed. As parts of the methodology were developed, examples with actual load and solar data and simulated generating systems were considered. In Chapter 7, more case studies are performed followed by discussion. Chapter 6 deals with the solution of the economic dispatch. How the economic dispatch solution is related to PV system performance and generation control is discussed in Chapter 6.

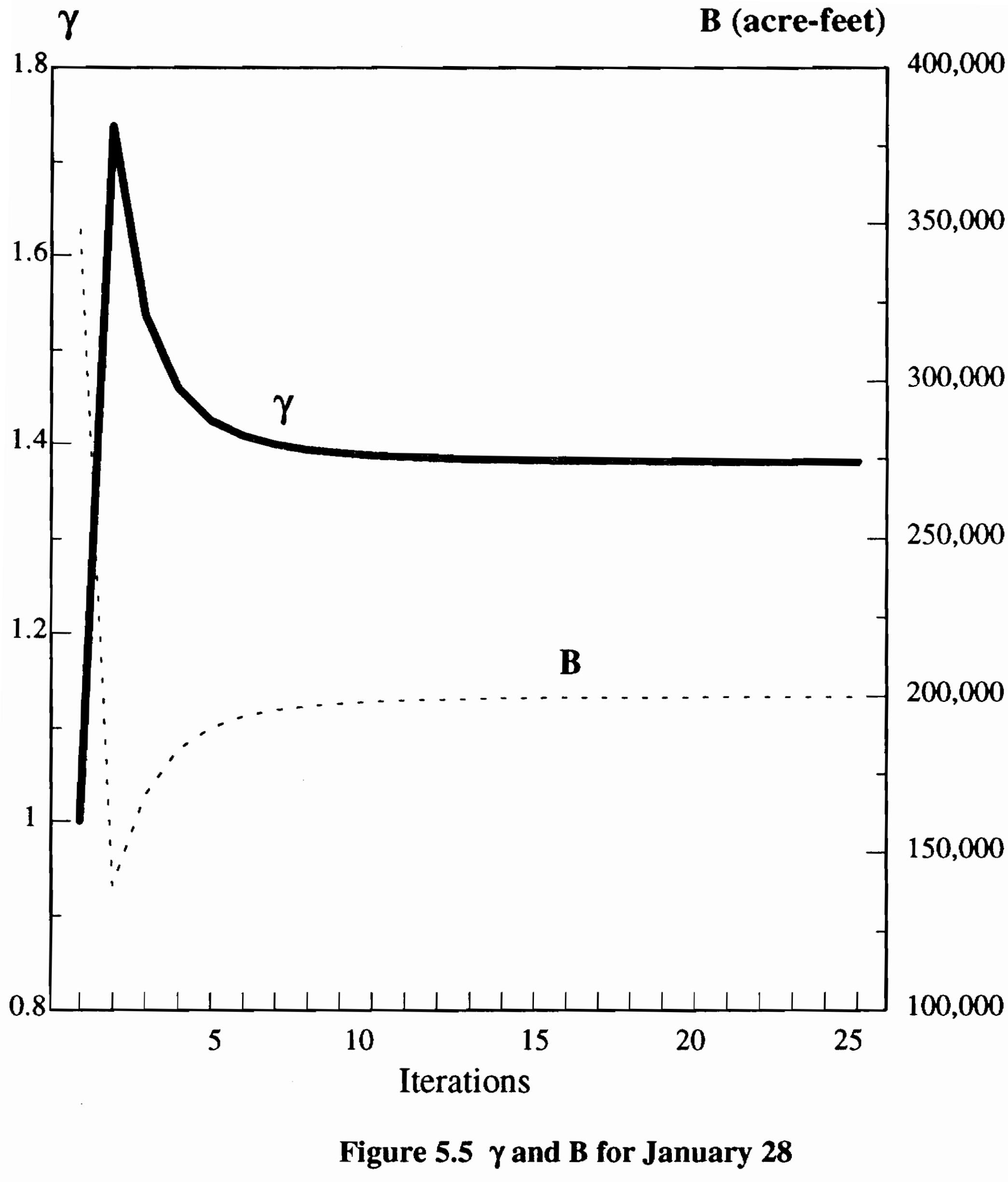


Figure 5.5 γ and B for January 28

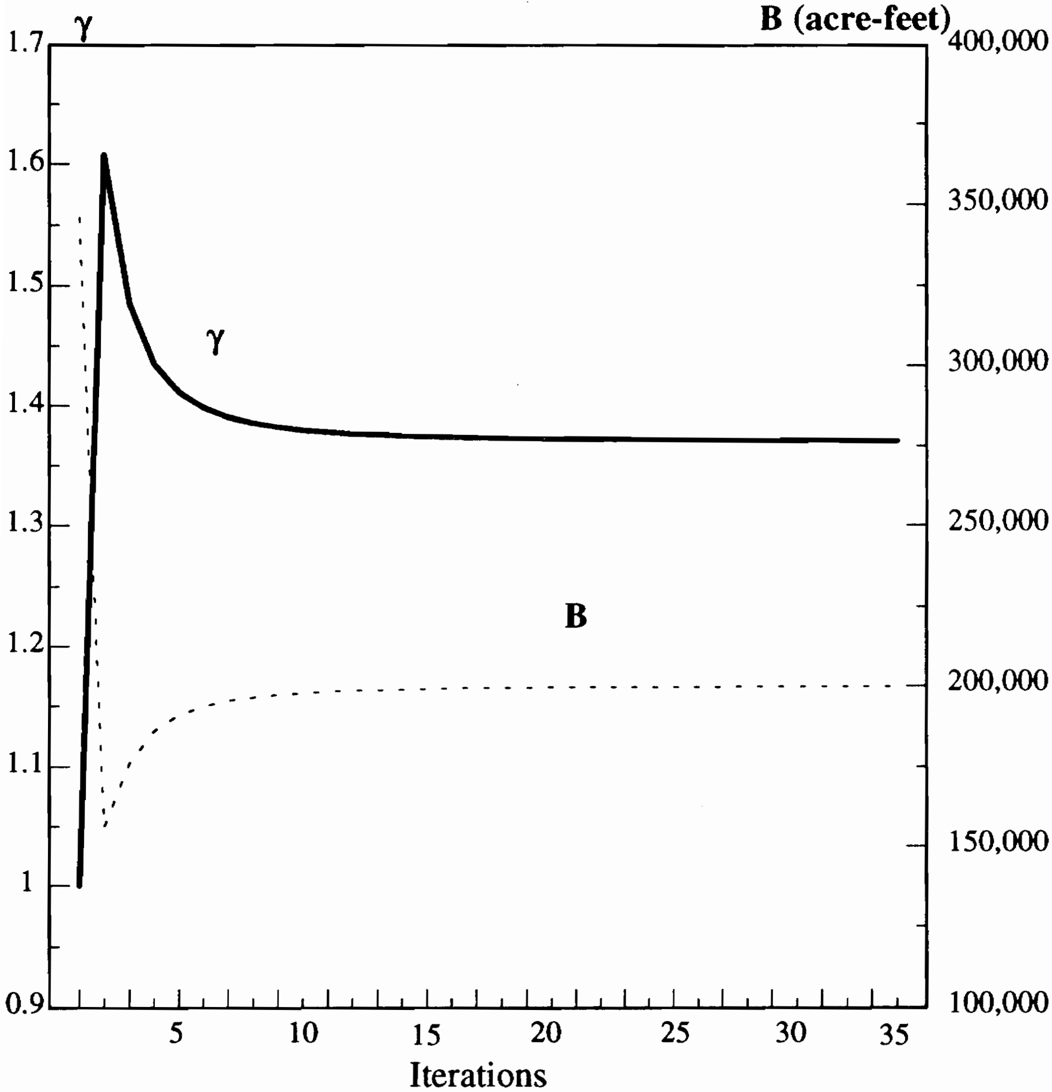


Figure 5.6 γ and B for July 10

Table 5.8 Operation Summary for January 28

Hour	Total Demand (MW)	Disp. Gen. (MW)	CT Gen. (MW)	Hydro Gen. (MW)	PSH Gen. (MW)	Tie-Line Inter. (MW)	Spinning Reserve (MW)	Production Cost ($)
1	8036	7213	0	449	375	0	1363	290,941
2	7971	7151	0	445	375	0	1429	288,503
3	7994	7173	0	446	375	0	1506	289,355
4	8095	7270	0	452	375	0	1804	293,159
5	8264	7433	0	461	375	0	2031	299,559
6	8759	7895	0	490	375	0	2940	317,942
7	9752	9182	0	569	0	0	1748	371,063
8	10571	9445	120	631	375	0	1549	387,260
9	10559	9435	120	630	375	0	1561	386,710
10	10333	9348	0	610	375	0	1668	378,211
11	10009	9297	120	587	0	0	1616	380,780
12	9715	9149	0	566	0	0	1784	369,647
13	9330	8430	0	525	375	0	2670	339,587
14	9065	8182	0	508	375	0	2935	329,488
15	8783	7918	0	491	375	0	3116	318,829
16	8616	7759	0	481	375	0	3284	312,508
17	8719	7857	0	487	375	0	3181	316,398
18	9383	8480	0	528	375	0	2516	341,637
19	10061	9348	120	594	0	0	1459	382,994
20	10046	9334	120	592	0	0	1474	382,294
21	9911	8965	0	571	375	0	1989	361,784
22	9578	8660	0	543	375	0	1522	349,029
23	9005	8130	0	505	375	0	1491	327,366
24	8279	7445	0	462	375	0	1418	300,049

Table 5.9 Operation Summary for July 10

Hour	Total Demand (MW)	Disp. Gen. (MW)	CT Gen. (MW)	Hydro Gen. (MW)	PSH Gen. (MW)	Tie-Line Inter. MW)	Spinning Reserve (MW)	Production Cost ($)
1	8192	8289	0	407	-500	0	1904	337,107
2	7768	7875	0	389	-500	0	2337	320,723
3	7450	7575	0	377	-500	0	2648	309,011
4	7271	7400	0	370	-500	0	2829	302,227
5	7300	7429	0	371	-500	0	2800	303,333
6	7669	7784	0	385	-500	0	2431	317,182
7	8392	8477	0	415	-500	0	2507	344,625
8	9203	9252	0	452	-500	0	1697	376,025
9	9946	9092	0	479	375	0	2954	369,506
10	10519	10481	0	538	-500	0	2381	428,374
11	11083	10987	0	596	-500	0	1818	451,544
12	11643	10440	240	588	375	0	1498	436,336
13	12142	10463	690	614	375	0	1448	463,242
14	12455	10461	990	629	375	0	1535	484,468
15	12600	10500	1090	639	375	0	1886	494,396
16	12730	10614	1090	650	375	0	1760	499,313
17	12700	10587	1090	647	375	0	1790	498,097
18	12442	10453	990	628	375	0	1844	483,592
19	12130	10453	690	613	375	0	1860	462,370
20	11727	10326	440	586	375	0	2013	441,675
21	11401	10448	0	577	375	0	1899	426,937
22	10754	10695	0	558	-500	0	1646	438,030
23	9785	9799	0	486	-500	0	1815	398,845
24	8822	8887	0	434	-500	0	1578	361,156

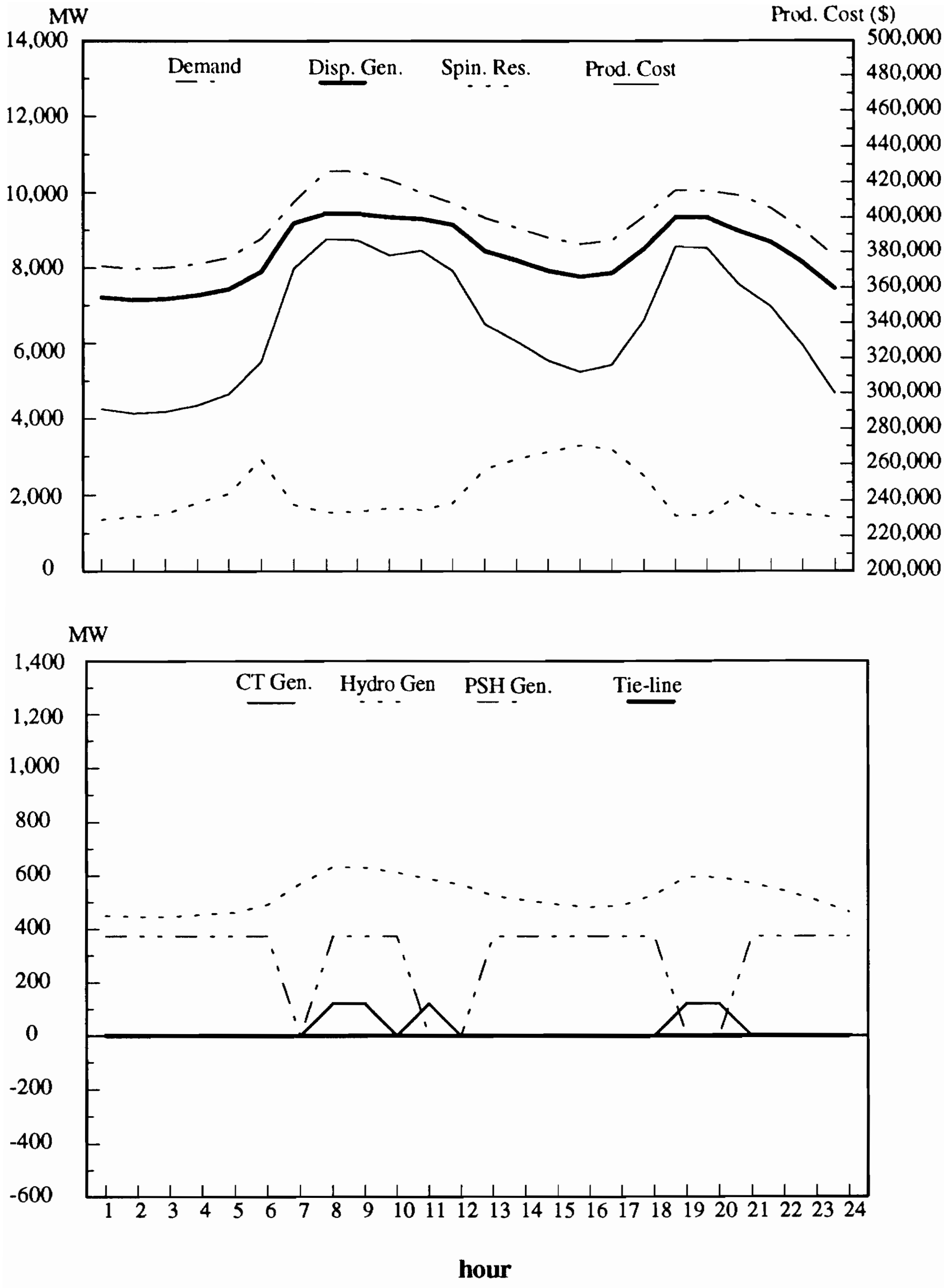


Figure 5.7 System Performance for January 28

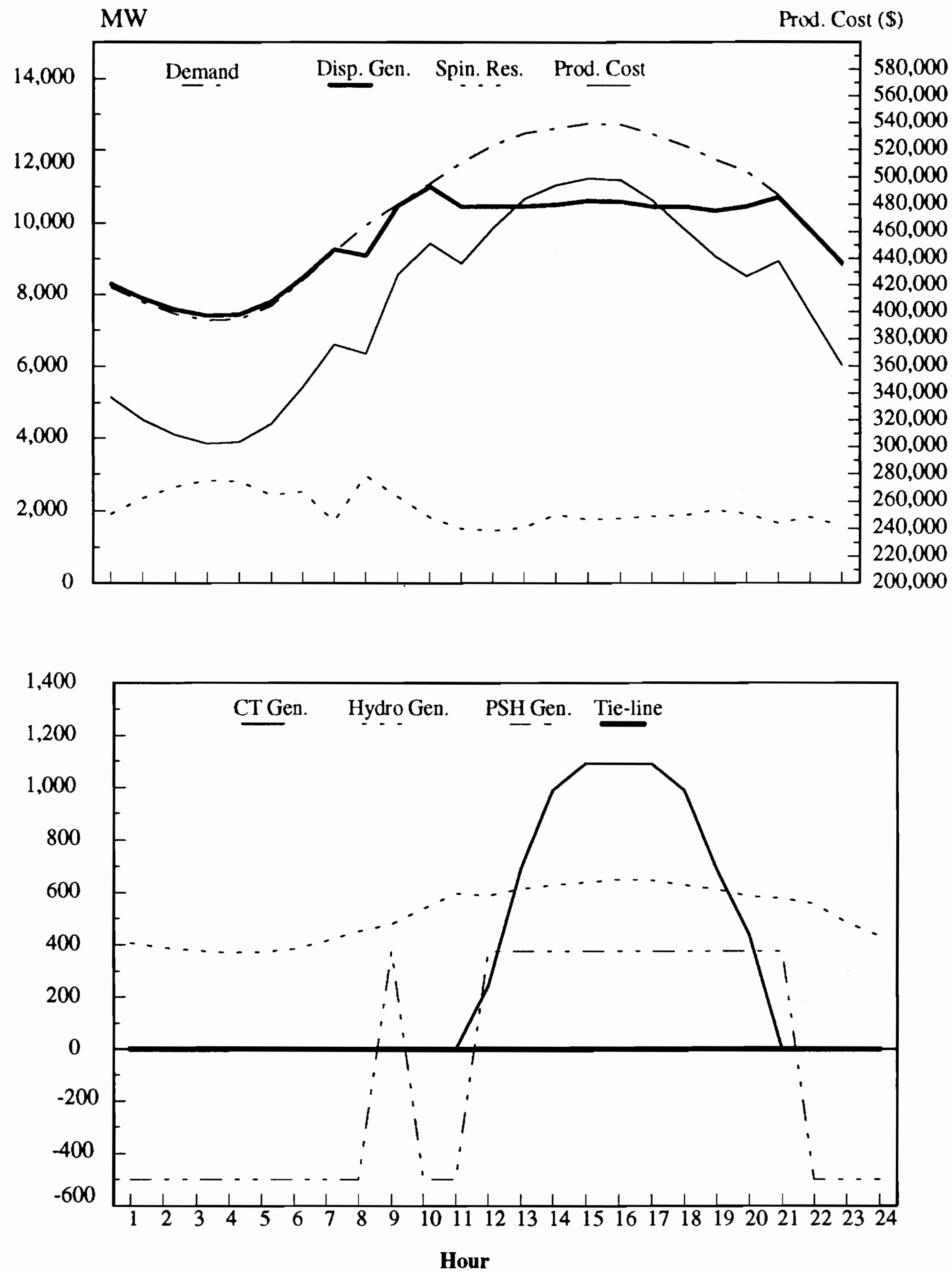


Figure 5.8 System Performance for July 10

CHAPTER 6.

SYSTEM OPERATION WITH PHOTOVOLTAICS

6.1 PV Operation Requirements and Generation Control

While photovoltaic and wind energy systems are expected to increase available spinning reserves, reduce fuel consumption, fuel costs, operating and maintenance costs, and water discharge, their optimal operational and economical values are not achieved yet. To achieve optimal operational and economical values of such non-conventional energy systems, a compromise between economics and system security is required. It is, in fact, the key to enhance the value of such "free energy" sources. In this section, the operation requirements for normal operation and generation control with PV systems are discussed. The relations between PV generation control on one hand, and economic dispatch and automatic generation control, on the other hand, are presented. Next, the economic dispatch solution is discussed. The operating strategy with PV system as shown in Figure 6.1, is recommended. It is applicable to other renewable energy systems.

6.1.1 PV Operation Requirements

The PV system can be integrated into normal system operation if

- Its long-term trends can be predicted,

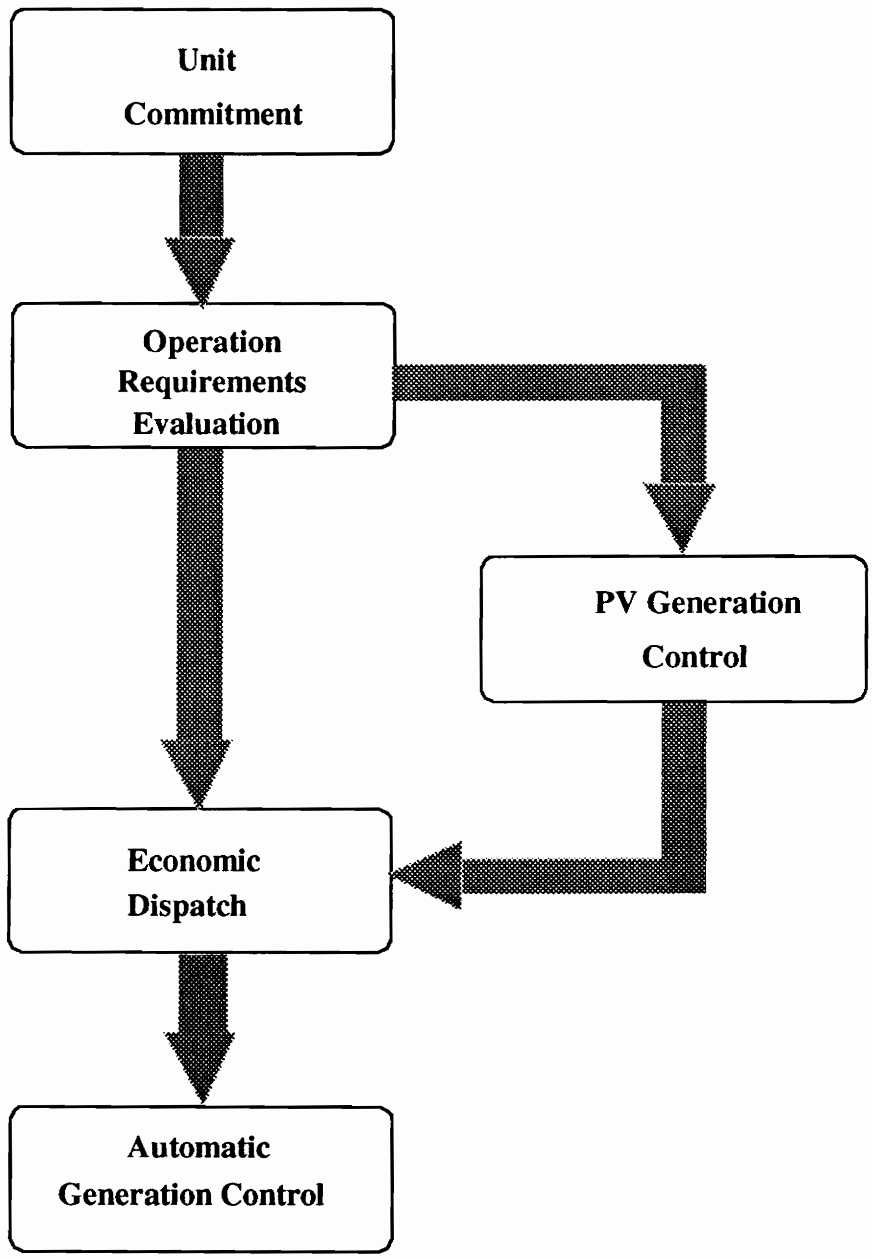


Figure 6.1 Operation Strategy with a PV System

• The electric utility system has sufficient flexibility to accommodate the unpredictable short-term fluctuations and uncertainties in the long-term forecast. Three types of operating requirements must be monitored during system operation:

• Operating reserve;

• Unloadable generation; and

• System response.

The operating reserve, also known as spinning reserve, is defined as the generation capacity above firm load that can be brought up to meet generation deficiencies caused by load increase, loss of generation, and decrease in PV power output. The unloadable generation is defined as the amount of on-line generation capacity that can be backed off to cope with a sudden decrease in load or increase in PV power output. Finally, system response, referred to by load-following capability of the power system depends on the ramping capability of the load-following generating units. The ramping capability of these units depends on their physical characteristics, generation history, control strategies, and load-generation mismatch.

Attempts to meet these requirements are made throughout the unit commitment and economic dispatch programs. In the unit commitment, enough units are committed to meet load plus losses and to provide adequate spinning reserves. Before, the economic dispatch is executed, operating requirements are determined. The three key quantities are the system ramping in the upward and downward directions, PV power output fluctuations, and load variations. The rampup and ramp down capacities are given by:

$$PUP_{t+1} = \sum_{i=1}^{N_{th}+N_h}[\min(P_{i,t+1}^{\max} - P_{it} \ , \ P_i^{\max} \times Ru_i \times \Delta T)] \qquad (6.1)$$

and

$$PDN_{t+1} = \sum_{i=1}^{N_{th}+N_h}[\min(P_{it} - P_{i,t+1}^{min} \ , \ P_i^{max} \times Rd_i \times \Delta T)] \qquad (6.2)$$

The PV power fluctuation is computed as the difference of PV power output between two consecutive intervals. Similarly, the load variation is the load increase/decrease from one interval to the next. The PV generation control commands are issued based on the sign and magnitude of these quantities.

6.1.2 PV Generation Requirements

Five scenarios are possible, each requires specific actions. These are:

1. The PV power output increase is less than or equal to the system ramping capacity in downward direction;

2. The PV power output decrease is less than or equal to the system ramping capacity in the upward direction;

3. The PV power output increase is larger than the system ramping capacity in the downward direction;

4. The PV power output decrease is larger than the system ramping capacity in the upward direction;

5. The minimum dispatchable generation plus PV power output is larger than the total dispatchable load plus losses.

The first two scenarios can happen provided that adequate spinning reserves are available through the unit commitment and that the rate of change of the PV system fluctuations match the system ramping capability. In this case, the PV is entirely accepted and the system security is maintained. The economic dispatch is executed to determine units loading.

Scenarios three and four can cause frequency deviations resulting in high area control errors. Remedy actions must be taken to maintain system security. This includes:

- Increasing scheduled tie-line flows;
- Bringing more units on-line to increase the load carrying capability;
- Increasing ramping capability of certain on-line units to operate at higher power level to increase system load carrying capability; and
- Decreasing PV power output.

Tie-line flow increase enables to export excess PV power output, in case 3. In case 4, more units are scheduled to increase system ramping in the upward direction. Thus load plus losses is satisfied. This requires that these units be on a standby mode and that additional costs are incurred to maintain these units. In exceptional circumstances, on-line units can have higher ramping rate, but for a short time. Finally, fast starting units such as combustion turbines, hydro and pumped storage units can scheduled to reduce power mismatch. Under action four, PV power output can be reduced for that particular time interval by blocking off some PV arrays or shutting down the entire facilities according to priority and constraints. This control option is discussed in details in the next section. It is expected that this action would increase PV penetration levels but result in "free Energy" wastage.

The outcome of the operation requirements module is to obtain an estimate of the maximum penetration level of PV generation and maximum tie-line flows for every five to ten minutes. The fifth scenario is somewhat like the third, but accounts for load variations. It is the function of the automatic generation control and load frequency control to correct the mismatch between the load and the generation.

6.1.3 PV Generation Control

By virtue of design, distributed PV systems have less fluctuating power output and offer generation control options. Two types of PV control actions can be envisioned:

- The PV facility is entirely disconnected from the grid; or
- A part of the facility is disconnected, so that the facility would be operating at power level lower than the available capacity.

Under either control type, the PV facilities are disconnected according to certain rules. These rules account for PV power fluctuations frequency and magnitude, size, operating costs, and forecasted performance. Other parameters include reactive power requirements, voltage stability (on-line load flow analysis is required to identify which PV facility needs to be disconnected), transmission, minimum on and off-times, and terms of contractual agreements. A dynamic priority list can be generated that comprises of these parameters. At this point, PV facility with the highest and most frequent fluctuations is disconnected first. In addition, weather forecast can help to identify PV facilities with lasting intermittency. Once the PV operation requirements are obtained, economic dispatch can performed for the next five to ten minutes.

6.2 Economic Dispatch Problem

The various variables and parameters used in formulating and solving the economic dispatch problem are listed below.

Annotation

λ_t	System incremental cost ($/MWh);
μ_t	Spinning reserves penalty cost ($/MWh);
γ_j	Hydro dispatching penalty for hydro plant j ($/MW);
N	Number of on-line thermal plants, defined by the unit commitment;
M	Number of on-line hydro plants, defined by the unit commitment;

T	Number of periods over planning horizon;
i	Thermal l power plant index;
j	Hydro plant index;
t	Time interval index;
ΔT	Economic dispatch interval, (10 minutes);
P_i^{min}	Minimum power output for thermal unit i ,(MW);
P_i^{max}	Maximum power output for thermal unit i, (MW);
P_{it}	Power output for thermal unit i at time t, (MW);
$Rd_{i(j)}$	Ramp-down rate for unit i (j), (%/minute);
$Ru_{i(j)}$	Ramp-up rate for unit i(j), (%/minute);
a_i b_i c_i	Cost function coefficients for thermal power plant i;
$C_i(P_{it})$	Production cost for thermal unit i at time t, ($/hr);
Ph_{jt}	Power output for hydro unit j at time t, (MW);
Ph_j^{min}	Minimum power output for hydro unit j, (MW);
Ph_j^{max}	Maximum power output for hydro unit j, (MW);
d_j e_j f_j	Discharge rate coefficient for hydro unit j;
q_{jt}	Discharge rate for hydro unit j at time t, (acre-ft/hr);
Bj	Daily water discharge for unit j, (acre-feet);
Pd_t	System load at time t, (MW);
Pl_t	Total system losses at time t, (MW);
PV_t	Total PV power output at time t, (MW);
SR_t	Total spinning reserves at time t, (MW);
$Ptie_t$	Tie-line power due to PV excessive power output at time t, (MW).

The cost FC_i of operating a unit i may be expressed as the product of fuel cost $fcst_i$ and heat rate HR_i :

$$FC_{it} = fcst_i \times HR_{it}$$

$$FC_{it} = fcst_i \times (a_i + b_i P_{it} + c_i P_{it}^2) \quad (\$/hr) \qquad (6.3)$$

For a hydroelectric, pumped-storage hydro, photovoltaic, and wind energy systems, operating costs are composed of operating and maintenance (O&M) costs. Their cost is added to the total cost.

The water discharge rate $q_j(P_{jt})$ for hydro unit j during interval t is given by:

$$q_{jt}(P_{jt}) = (d_j + e_j P_{jt} + f_j P_{jt}^2) \quad (acre - feet / hr) \qquad (6.4)$$

Now consider a system with N_{th} thermal plants and N_h hydro plants operating essentially at constant head. Then the total cost F_t of generation at time t is given by:

$$F_t = \sum_{i=1}^{N_{th}} F_i(P_{it}) + \sum_{j=1}^{N_h} F_j(P_{jt}) \quad (\$ / hr) \qquad (6.5)$$

It is desired to minimize the total fuel cost *TF* over the entire scheduling period.

$$TF = \sum_{t=1}^{T} F_t \quad (\$) \qquad (6.6)$$

where T is the number of periods in the scheduling periods.

The minimization is carried out such that:

i) The total system generation matches the power demand D_t and system losses Tl_t, that is for time t:

$$PV_t + \sum_{i=1}^{N_{th}} P_{it} + \sum_{j=1}^{N_h} P_{jt} = D_t + Tl_t + Ptie_t \qquad (6.7)$$

Tl_t is given by:

$$Tl_t = K_{lo} + \sum_{k=1}^{N_{th}+N_h} B_{ko} P_{kt} + \sum_{k=1}^{N_{th}+N_h} \sum_{i=1}^{N_{th}+N_h} P_{kt} B_{ki} P_{it} \qquad (6.8)$$

where

P_{it} and P_{kt} are source loadings at time t, and

B_{ki} are the transmission loss formula coefficients.

ii) A certain amount of available power must be kept which can be quickly mobilized in few minutes to deal with unexpected unit breakdown or unavailability, increase in load, drop in intermittent power output, etc. This available power is termed spinning reserve and can be supplied by on-line units. Minimum spinning reserve at time t, SR_t must always exist.

$$\sum_{i=1}^{N_{th}}(P_{it}^{\max} - P_{it}) + \sum_{j=1}^{N_h}(P_{jt}^{\max} - P_{jt}) \geq SR_t \qquad (6.9)$$

The available spinning reserve levels are provided through the 24-hour unit commitment program.

iii) The volume of water available for discharge for each hydro plant j must not exceed a well defined level B_j. B_j depends on the rain fall for the season and operational considerations. That is:

$$\sum_{t=1}^{T} q_{jt}(P_{jt}) \leq B_j \qquad (6.10)$$

iv) Thermal and hydro power plant capacity limits, i.e.,

$$P_l^{\min} \leq P_{lt} \leq \mathbf{P}_l^{\max} \qquad \mathbf{(6.11)}$$

$$\textbf{for } l = 1, 2, \ldots, N_{th} \qquad \textbf{and } l = 1, 2, \ldots, N_h$$

v) Ramping limitations, i.e.,

$$\Delta T \times Rd_l \times P_l^{\max} \leq P_{lt} - P_{lt-1} \leq \quad \Delta T \times Ru_l \times P_l^{\max} \qquad (6.12)$$

for $l = 1, 2, \ldots, N_{th}$ and $l = 1, 2, \ldots, N_h$

where

ΔT is economic dispatch interval.

vi) Other constraints include water discharge limit, emission allowances, fuel consumption rates and allowances, reactive power requirements, and unit minimum down time and up time.

The forth mentioned economic dispatch problem can be solved using non-linear optimization techniques. Among these are the penalty methods, gradient projection, Lagrangian methods, direct search, and recently, heuristics. The Lagrangian method is considered in this study. Without loss of generality , only load, spinning reserve, and maximum water discharge constraints are considered in the solution. In particular, updated capacity limits are useful to track the optimal generation levels of on-line units. The augmented cost function L is given by:

$$\begin{aligned} & L(P_{it}, P_{jt}, \lambda_t, \mu_t, \gamma_j) \\ & = \sum_{t=1}^{T} \{ \sum_{i=1}^{N_{th}} F_i(P_{it}) + \lambda_t [Ptie_t + D_t + Tl_t - \sum_{i=1}^{N_{th}} P_{it} - \sum_{j=1}^{N_h} P_{jt} - PV_t] \qquad (6.13) \\ & + \mu_t [\sum_{i=1}^{N_{th}} (P_{it}^x - P_{it}) + \sum_{j=1}^{N_h} (P_{jt}^x - P_{jt}) - SR_t] \} + \sum_{t=1}^{T} \sum_{j=1}^{N_h} \gamma_j [q_{jt}(P_{jt}) - B_j] \end{aligned}$$

$$P_{it}^{m} = \max[P_i^{\min}, P_{i,t-1} - P_i^{\max} \times Rd_i \times \Delta T]$$

$$P_{it}^{x} = \min[P_i^{\max}, P_{i,t-1} + P_i^{\max} \times Ru_i \times \Delta T] \qquad (6.14)$$

for $i = 1,2,\ldots,N_{th}$ and $j = 1,2,\ldots,N_h$ $(Rd > 0)$

where

P_{it}^{x} and P_{it}^{m} are the updated minimum and maximum capacity limits.

Optimality Conditions

The optimality conditions are made up of two sets. The first is the problem constraints:

1-a) The power balance equation should be satisfied at each time step.

1-b) The spinning reserve balance equation should be satisfied at each time step.

1-c) The daily volume of water constraints should be satisfied at each hydro plant.

The second set is based on variational arguments, this means that the derivative of L with respect to P, λ, μ, and γ must equal zero.

$$\frac{\partial L}{\partial P_{it}} = \frac{\partial L}{\partial P_{jt}} = \frac{\partial L}{\partial \lambda_t} = \frac{\partial L}{\partial_{\mu t}} = \frac{\partial L}{\partial \gamma_j} = 0 \qquad (6.15)$$

That is:

2-a) for each thermal unit i,

$$\frac{dF_i(P_{it})}{dP_{it}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{it}} - 1) - \mu_t = 0 \qquad (6.16)$$

2-b) for each hydro unit j,

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}} - 1) - \mu_t = 0 \qquad (6.17)$$

Rearranging (6.16) and (6.17) yields the famous hydro thermal coordination equations for each time t:

$$\frac{dF_{it}(P_{it})}{dP_{it}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t + \mu_t \qquad \textbf{for i = 1,2,...,N}_{\textbf{th}}$$

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + \lambda_t \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t + \mu \qquad \textbf{for j = 1,2,...,N}_{\textbf{h}} \qquad (6.18)$$

These two equations along with the capacity limits, power and demand balance, spinning reserve balance, and other physical constraints constitute a set of non-linear equations that are time dependent and require iterative methods to solve.

Interpretation

The energy price λ_t and the spinning reserve price μ_t (both in \$/MWh) would be adjusted so that system load plus losses and spinning reserve requirements are mutually satisfied.

γ is know as the incremental water value (\$/MW) and depends on generation mix, fuel costs and daily energy requirements. It gives an indication of how to achieve minimum fuel cost without violating maximum water allowances.

The optimality conditions require equal penalized incremental fuel cost (thermal), and penalized incremental rate of water discharge.

Alternative Solution

To reduce the complexity of the problem, the following modifications are made. The spinning reserve balance can be rewritten as:

$$\sum_{i=1}^{N_{th}} P_{it}^{\max} + \sum_{j=1}^{N_h} P_{jt}^{\max} \geq D_t + Tl_t + SR_t \qquad (6.19)$$

The new Lagrangian function and coordination equations are:

$$\begin{aligned}
&L(P_{it}, P_{jt}, \lambda_t, \mu_t, \gamma_j) \\
&= \sum_{t=1}^{T} \{ \sum_{i=1}^{N_{th}} F_i(P_{it}) + \lambda_t [Ptie_t + D_t + Tl_t - \sum_{i=1}^{N_{th}} P_{it} - \sum_{j=1}^{N_h} P_{jt} - PV_t] \qquad (6.20) \\
&+ \mu_t [\sum_{i=1}^{N_{th}} P_{it}^{x} + \sum_{j=1}^{N_h} P_{jt}^{x} - (D_t + Tl_t + SR_t] \ \} \\
&+ \sum_{t=1}^{T} \ \sum_{j=1}^{N_h} \gamma_j [q_{jt}(P_{jt}) - B_j]
\end{aligned}$$

and

$$\frac{dF_{it}(P_{it})}{dP_{it}} + (\lambda_t - \mu_t) \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_t \qquad \textbf{for } \mathbf{i = 1, 2, \ldots, N_{th}}$$

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} + (\lambda_t - \mu_t) \times (\frac{\partial Tl_t}{\partial P_{jt}}) = \lambda_{tt} \qquad \textbf{for } \mathbf{j = 1, 2, \ldots, N_h} \qquad (6.21)$$

respectively. This suggests that spinning reserve contribution would be a function of system losses as is the case for the load. If lossless system is assumed, simpler coordination equations can be obtained .

$$\frac{dF_{it}(P_{it})}{dP_{it}} = \lambda_t \qquad \text{for } i = 1,2,\ldots,N_{th}$$

$$\frac{dq_j(P_{jt})}{dP_{jt}} = \frac{\lambda_t}{\gamma_j} \qquad \text{for } j = 1,2,\ldots,N_h \qquad (6.22)$$

The economic dispatch solution becomes straightforward.

6.3 Proposed Economic Dispatch Solution

For the purpose of this study, the following assumptions are made:

- The unit commitment is performed to provide enough spinning reserves for each hour. During the economic dispatch phase, spinning reserves are updated to account for the lower and upper generation limits, load variations and intermittent generation power fluctuations.

- Transmission losses are included in the economic dispatch, however, constant reciprocal penalty factors, $crpf_i$ (and cpf_i) are used. The coordination equations can be rewritten as:

$$\frac{dF_{it}(P_{it})}{dP_{it}} = \lambda_t(1.-\frac{1}{cpf_i}) = \lambda_t(1.-crpf_i) \qquad \text{for } i = 1,2,\ldots,N_{th}$$

$$(6.23)$$

$$\gamma_j \frac{dq_j(P_{jt})}{dP_{jt}} = \lambda_t(1.-\frac{1}{cpf_j}) = \lambda_t(1.-crpf_j) \qquad \text{for } j = 1,2,\ldots,N_h$$

- The total startup cost for the day is the sum of dispatchable generation startup costs and combustion turbines startup costs incurred by the economic dispatch.

- The optimal value of γ given by the unit commitment on hourly basis. It is updated to reflect the new load profile and size, PV power output and any change in the system characteristics. For each interval t and plant j, the value of γ_j is given by γ_{jt} as follows:

$$\gamma_{jt} = \gamma_j \times \exp(-1. + \frac{\text{Power Demand } + \text{Ptie}_t - \text{PV}_t}{\text{Net Peak Load}}) \qquad (6.24)$$

where

Power demand is the sum of system load, losses and tie-line flow (sales); and

Net Peak Load is the effective peak load.

6.3.1 Equal Incremental Cost Criteria

The optimal solution requires that the dispatched units should run at the same lambda, thus the equal incremental cost criteria. The initial value for incremental cost λ is obtained through the closed-form solution. However, because of ramping rates and power output constraints, the solution may not converge. In this case, λ must be adjusted until the load and losses requirements are met. The new value λ is obtained using the procedure outlined in the unit commitment.

6.4 Automatic Generation Control

Computer control of the output of each plant and of each unit within the plant is common practice in power-system operation. By continually monitoring all power plant outputs and the power flowing in interconnections interchange of power within other systems is controlled. In discussing control the term area means that part of an interconnected system in which one or more companies control their generation to absorb their own load changes and maintain a prearranged net interchange of power with other areas for specified periods. Monitoring the flow of power on the tie-lines between areas determines whether a particular area is absorbing satisfactorily all the load changes within its own boundaries. The function of control is to require the area to absorb its own load changes, to provide the agreed net interchange with the neighboring areas, to determine the desired generation of each plant in the area for economic dispatch, and to cause the area to do its share to maintain the desired frequency of the interconnected system. Much of the associated functionality is provided by the by the Automatic Generation Control (AGC) program operating within the control center computer. Power system operators play an important role as well. They buy and sell power to neighboring utilities, coordinate plant operation with generation plant operators within their own company, and interact with the AGC program to monitor its results and to provide it with various input that reflect current operating conditions.

The AGC function is broadly divided into two major functions- load frequency control (LFC) and economic dispatch. The function of LFC is to regulate system electrical frequency error to zero and to distribute system generation among control areas so that the net area tie flows match net area tie flow schedules. Similarly, the function of economic dispatch is to distribute area generation among area generation sources so that area operating costs are minimized. In each case, constraints such as unit power output and ramping rate limits must be met. In addition, AGC function is to match system generation to system load. This is associated with system primary or governor speed control; turbine speed governors respond proportionally to local frequency deviations and normally bring the rate of change of frequency to zero within stipulated time frame, in the order of few seconds. In meeting these objectives, generation sources in the system are operating in one of the following operating states:

- Base not regulating: fixed plant generation;
- Base regulating: power output level changes with the system load;

- Automatic non-economic regulating: power output level changes around a base setting as area control changes; and
- Automatic economic regulating: unit power output is adjusted with the area load and area control error, at the most economic setting.

6.4.1 Load Frequency Control

The function of load frequency control is to regulate its area control error (ACE) to zero, where

$$ACE = M - S + B \times (f - f_0) \qquad (6.25)$$

where

M	is the metered interchange;
S	is the scheduled net interchange;
B	is the frequency bias constant (positive);
f	is the actual frequency; and
f_0	is the scheduled frequency (60 Hz).

During system operation, the following performance criteria must be met as mandated by the North American Electric Reliability Council Operating Committee (NERC-OC):

- ACE must equal zero at least one time in all ten-minute periods;
- Average ACE for all ten-minute periods must be within specified limit that is determined from the control area's rate-of-change of load characteristics;
- After a disturbance condition, ACE must be returned to zero within 10 minutes; and
- Corrective action must be forthcoming within one-minute following a disturbance.

The NERC-OC performance are not always satisfied by the utility, in particular during the morning load pickup, when load and generator conditions change quickly and load/generator mismatches cause the value of ACE to exceed the utility's defined maximum ACE. The presence of renewable energy sources may add to the severity of the problem.

6.4.2 Impact of PV Power Fluctuations on Automatic Generation Control

Renewable energy sources such as PV power plants could potentially have significant impact upon existing methods of generation scheduling. Currently, these sources are small and are treated as negative loads that are themselves transparent to AGC. Understanding automatic generation control requirements calls for a better understanding of how renewable energy sources operation and operation requirements. As of today, PV and wind energy systems are treated, and for economic reasons, as uncontrollable energy sources. The work by Sadanandan et al. dealt with the impact of wind generation on load frequency control. The study indicated that wind generation introduced slowly changing components in the ACE that will appear as sustained under generation of over generation, and hence could violate regulation criteria. The results were based on simulated data. The study concluded that further limitation on wind generation penetration may be necessary to avoid regulation requirement violations.

An optimal solution to automatic generation control with renewable energy sources can be achieved in two stages: a dynamic economic dispatch and a load frequency control that is sensitive to renewable energy sources. The dynamic economic dispatch would have features such as unit valve point loading, and look-ahead capability. Under the automatic generation control, renewable energy sources must controlled for security reasons, and not for economic reasons. These are guidelines to control, for example, distributed PV systems:

- Develop of short-term weather forecasts and local and system-wide coordinated control of PV generation. This is done to reduce excessive PV generation excursions.
- Monitor PV power fluctuations and performance history. The PV system with highest number of fluctuations (frequency and size) must be turned off first for the next economic dispatch period.
- Monitor the spectral analysis of the PV sites, by considering the PV system as a source of error that can add to the system area control error under normal operation conditions. The PV site with significant low-frequency harmonics contents must not be scheduled for the next economic dispatch period.

While the scope of this dissertation is to assess interactions between the short-term fluctuations of renewable energy sources and load variations, automatic generation control can affect the economical and operational value of these energy sources. However, the automatic generation control adds to the dimension of the problem in hand, and therefore would be treated separately.

CHAPTER 7.

CASE STUDIES

In this chapter, weekly pumped-storage hydro scheduling, unit commitment and economic dispatch methodologies are tested for selected days under various assumptions and control options. The short-term system operation uses data provided by the long-term planning program. Long-term and medium-range planning with PV systems was studied in previous chapters. The aim was to investigate the impact of PV system on the electric system reliability, with the PV system was treated as a negative load and as a conventional unit. The forced outage rate and availability for the PV system are based on actual solar data. The interactions between weekly pumped-storage hydro and PV system were also discussed. System operation without and with PV system is discussed in this chapter. Four topics are considered, impact of load profile on the pumped-storage scheduling, constrained hydro dispatching with PV system, and impact of pumped-storage hydro and tie-line interchange on PV penetration levels. Impact of hydro availability and ramping rates on PV penetration levels are also discussed in this chapter. In previous studies, ramping rates, hydro availability and daily load variations were found to influence PV penetration levels and energy value. Optimization of PV system and energy storage for small applications as a function of load characteristics was undertaken in some of these studies [13-17, 126]. Similar approach used in space station can be applicable to electric utilities.

7.1 Impact of Load Profiles on Pumped-storage scheduling

The interactions between PV system and pumped storage scheduling were discussed in Chapter 5. One week in January and one in July were considered. It was found that PV energy value is influenced by scheduling pumped-storage. It was also found that PV generation itself can alter pumping and generation schedules. The weekly load profiles for both weeks were different, therefore, two different pumped storage schedules were obtained. To further explore the relationship between load shape and pumped storage hydro scheduling, four weeks representing the four seasons of the year were considered. The purpose is to show the interaction between pumped-storage scheduling and seasonal load variations. The impact of the initial water level at the reservoir will be also discussed. This is done on a weekly basis. The four weeks are January 21-27, May 22-28, July 16-23, and October 7-13. Each week features the medium load day of the month. Each week starts on Monday and finishes on Sunday. The reservoir initial volume is 50 percent. This is to allow pumping as early as Monday. Generating system characteristics and energy costs are given in Tables 6.4 and 7.1. The system described in these two tables reflect reference generating systems. Data in Tables 6.1 and 7.1 reflect the reference.

Figures 7.1 through 7.4 and Table 7.3 show weekly system performance for the selected weeks. The upper part of each figure displays system performance without pumped storage, the lower part shows system performance with pumped storage. The load is the sum of system demand plus losses and pumping requirements. Dispatchable generation is the sum of all dispatchable units.

Table 7.1 Low and High Energy and O&M Costs

Technology	Generation (MW)	Mix (%)	Energy Costs (¢/k Wh) Low	High
Nuclear	3000	20.00	3.10	9.00
Coal	7500	50.00	4.30	9.20
Large Oil	1200	8.00	5.30	9.70
Oil (CT)	530	3.55	8.10	16.80
Natural Gas (CT)	560	3.75	6.70	14.30
Hydro	1200	8.00	0.20	0.20
Tie-line Interchange	500	3.35	5.00	5.00
PS Hydro	500	3.35	3.50	3.50
Total	14990	100.00	**Source 124**	

* Based on the smallest unit and minimum loading
**Based on the smallest unit and at 50% loading
PV O&M costs are 5 mills/kWh

7.1.1 January Performance

The pumped storage plant was generating more than it was pumping. This is indicated by a positive PSH weekly generation, shown in column 4 of Table 7.2. The overall trend seems to keep the daily peak loads as close to each other as possible. For this week, production cost savings reached $549,072, while spinning reserves increased by 27510 MWh. CT generation did not change.

7.1.2 May Performance

More pumping than generation had occurred during this week. The pumped-storage plant was scheduled to generate only on Monday, where the highest peak load of the week occurred. Since the reservoir level was initially set at 50 percent, pumping continued throughout the week which increased production cost. However, CT generation was reduced to zero, while spinning reserves increased by about 60,000 MWh.

7.1.3 July Performance

High peak loads existed throughout the entire week. In particular, Wednesday and Friday featured the highest peak loads of the week. Higher baseload generation was required throughout the week for pumping. For this week, energy production cost increased due to more pumping than generation. Combustion turbine generation, however, decreased significantly. Total spinning reserves improved. The overall cost increase was $ 822,384. This is equivalent to $ 117,483 per day.

7.1.4 October Performance

The pumped-storage power plant was operating throughout the week in both pumping and generation mode. CT generation was significantly reduced by discharging water during peak load periods. Again, spinning reserves increased. The average daily production cost increase reached $145,567.

7.2 Impact of Initial Water Level in the Reservoir

It can be seen that excessive pumping was due to the initial level of the reservoir and increased overall production costs. This seems to be a non-economical alternative to generate electricity. Care must be taken to avoid pumping at the expense of high production cost. To test the methodology when the reservoir is full at the beginning of the week, only the weeks of January and July were considered. Results are shown in Table 7.3 and Figures 7.5 and 7.6 The total savings for the two weeks reached $ 1,124,816 and $ 87,200 respectively. As expected, the pumped-storage scheduling optimization results in significant cost savings, increase in spinning reserves, and reduction in combustion turbines generation during peak load periods, as is case the week in July.

7.2.2 Concluding Remarks

From the above discussion, the following key observations can be made:

- Pumped-storage scheduling reduced peak load and increased load during valley periods. This lead to a much lower peaking unit generation and increased baseload generation. It also lead to lower startup costs. This is due to higher baseload generation throughout the entire week.
- Pumped-storage scheduling increased system spinning reserves.
- The proposed pumped-storage scheduling methodology seems to improve load factor. This would indeed eliminate combustion turbine generation and tie-line interchange.

7.3 Conventional Hydro Dispatching

Given the pumped-storage hydro-thermal schedule, conventional hydro generation is then scheduled subject to hydro constraints. The constrained hydro dispatching methodology is based on a 24-hour time frame. A medium load day was considered. The initial reservoir level was 50 percent of full capacity. This is to allow pumping/generation at the beginning of the week. As seen in Figures 7.1 through 7.4, the pumped-storage plant was found to operate in both modes within a single 24-hour period. Figures 7.7 and 7.8 display hydro dispatching for May 22, and October 8. Table 7.4 lists daily system operation summary for the selected days. As seen from Figures 7.7 and 7.8, hydro plant power output increased with the load. For example, in May (Figure 7.7), the hydro plant power output reached 600 MW at 6:00 p.m. (peak load) and 300 MW at 3.00 a.m.. This is 100 percent increase. For October, the increase is in the order of 86 percent.

The capacity factor for the hydro plant varied from 42.92 percent in May to 43.57 percent in October.

The above results indicate that hydro power output is sensitive to load variation. Combined with high ramping rates and zero minimum power output, the proposed hydro dispatching makes hydro generation a suitable cushion for intermittent generation sources.

Table 7.2 Weekly System Operation Summary for all four seasons

Low Energy Costs (*)

Load (MWh)	CT Gen (MWh)	Disp. Gen (MWh)	PSH Gen. (MWh)	PSH Pumping (MWh)	Spinning Reserves (MWh)	Startup Cost ($)	Production Cost ($)	Energy Cost (mils/kWh)
January 21-27								
1 124 642	630	1 124 060	0	0	430 725	8157	45 884 528	40.80
1 125 340	630	1 112 001	15750	-3000	458 235	7934	45 335 456	40.29
May 22-28								
1 041 803	240	1 041 610	0	0	380 581	7444	41 773 920	40.10
1 040 575	0	1 060 734	3375	-23500	441 280	9037	42 912 608	41.24
July 16-22								
1 487 047	17270	1 469 772	0	0	432 996	21 758	59 430 816	39.97
1 485 552	14920	1 492 218	3375	-25000	493 274	19 735	60 253 200	40.56
October 7-13								
1 051 423	7320	1 044 163	0	0	408 828	10129	44 748 224	42.56
1 051 526	920	1 071 149	25500	-46000	509 141	5399	45 767 104	43.52

(*) Tie-line Generation was zero in all weeks

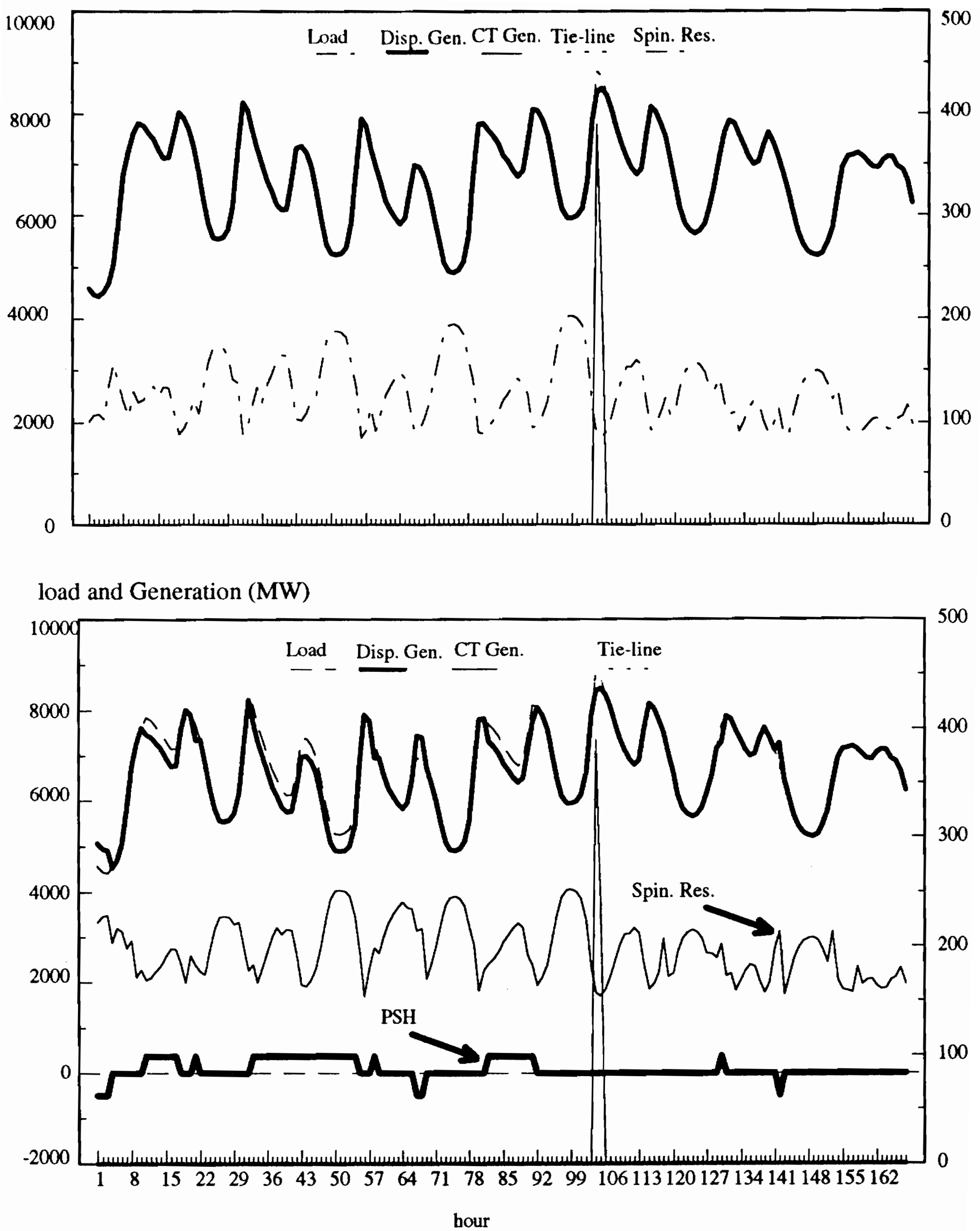


Figure 7.1 System Performance for January 21-27

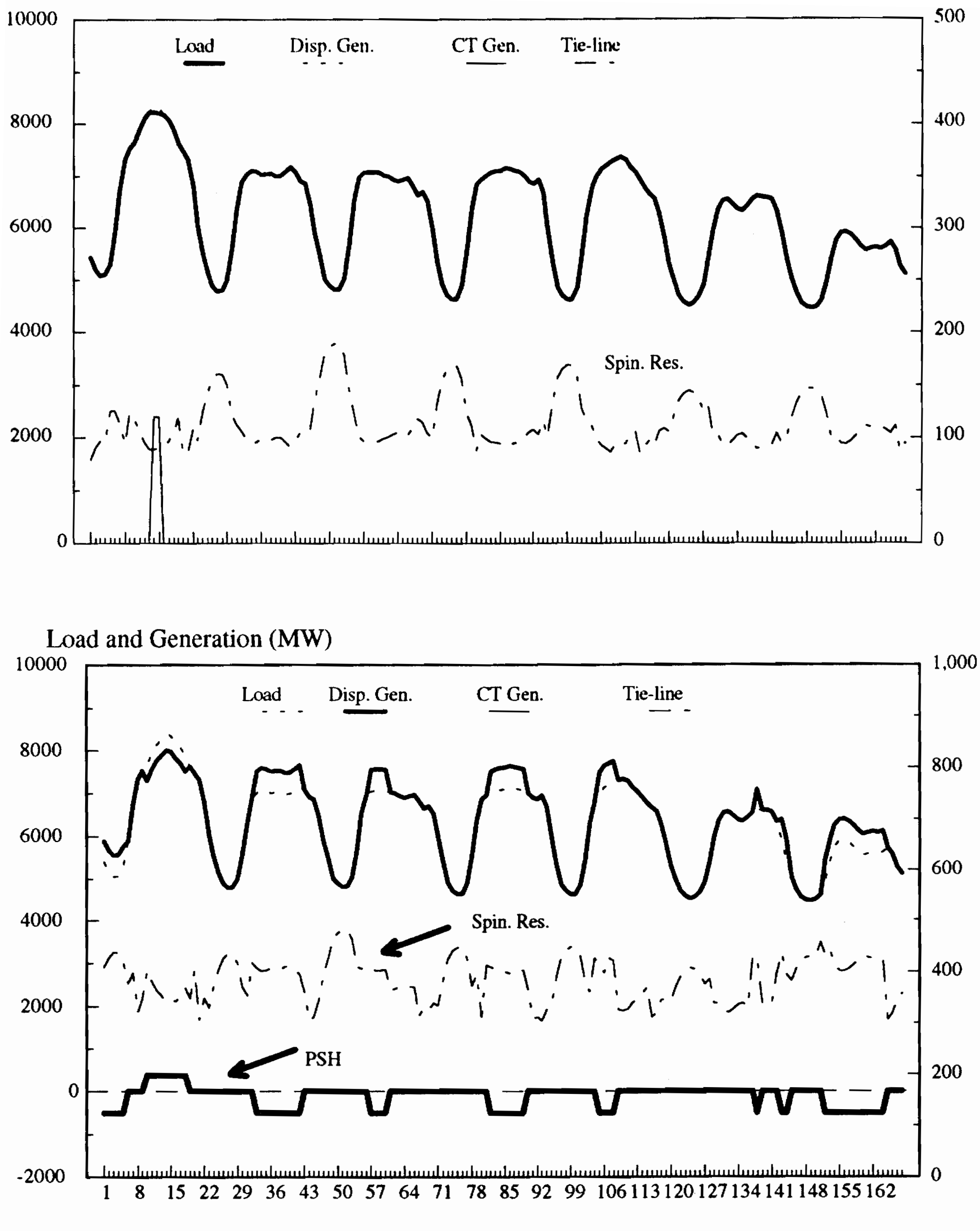


Figure 7.2 System Performance for May 22-28

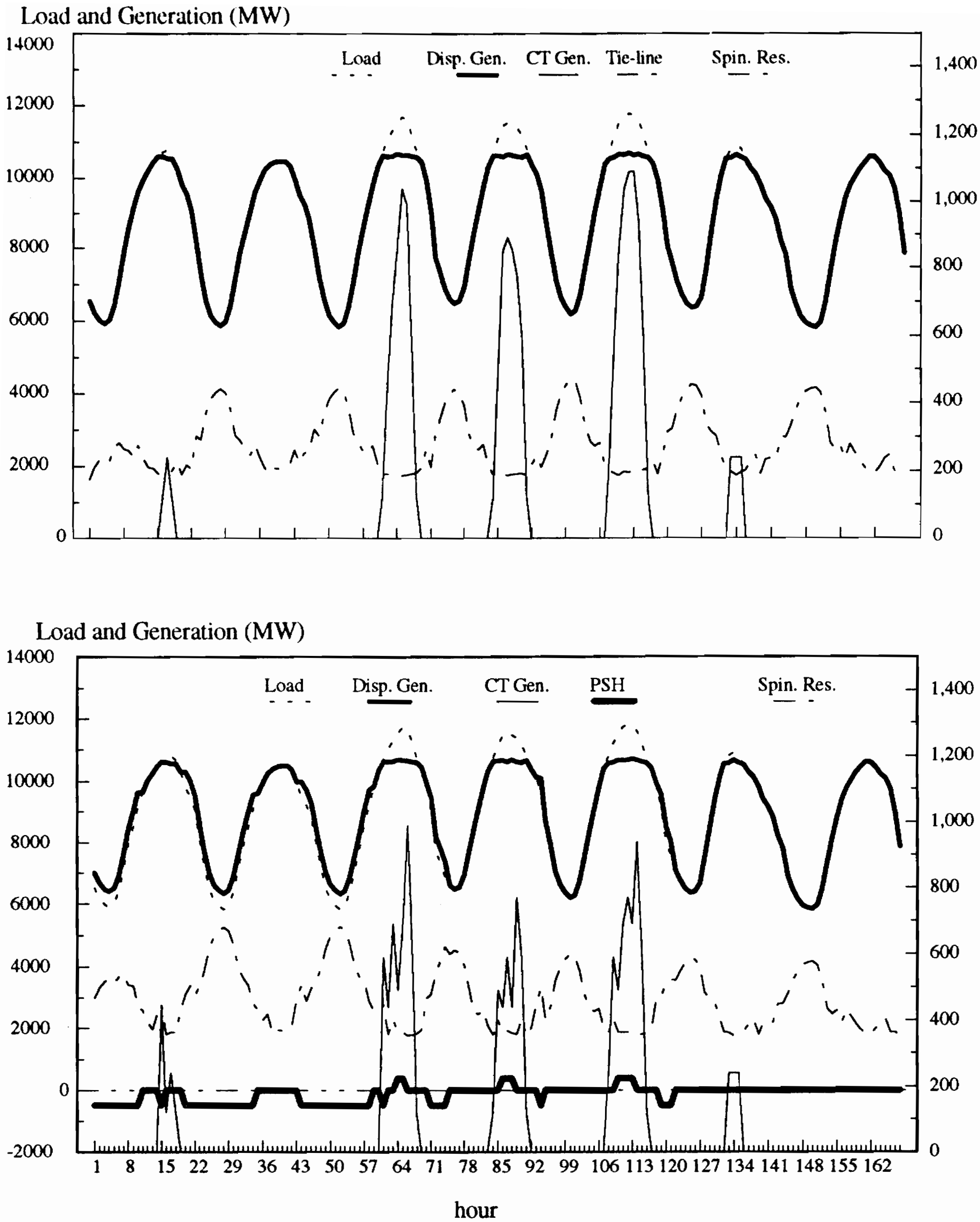


Figure 7.3 System Performance for July 16-22

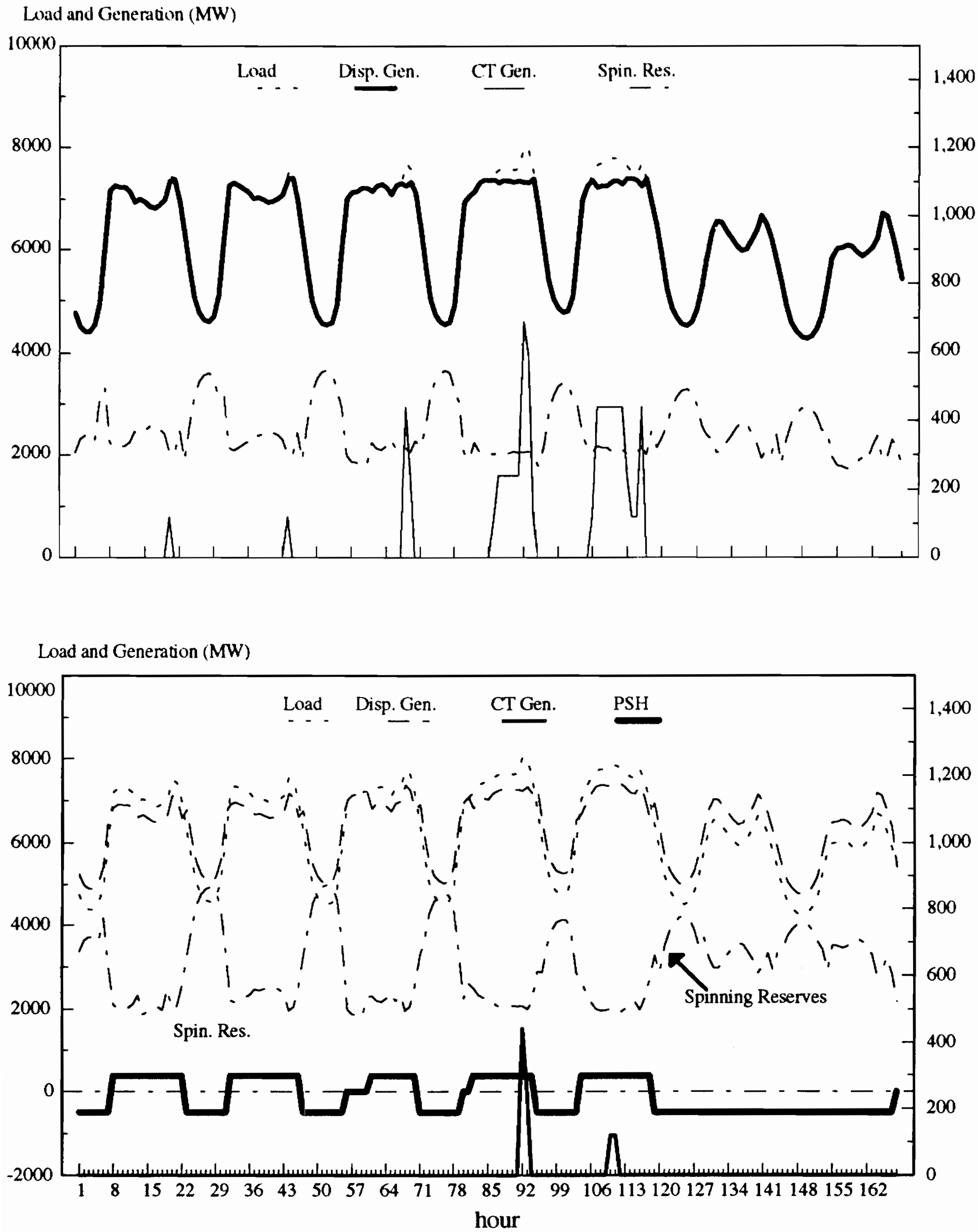


Figure 7.4 System Performance for October 7-13

Table 7.3 System Operation Summary for January and July at Full Reservoir Low Energy Costs (*)

Load (MWh)	CT Gen (MWh)	Disp. Gen (MWh)	PSH Gen (MWh)	PSH Pumping (MWh)	Spinning Reserves (MWh)	Startup Cost ($)	Production Cost ($)	Energy Cost (mils/kWh)
January 21-27								
1 124 642	630	1 124 060	0	0	430 725	8157	45 884 528	40.80
1 126 318	630	1 099 109	28125	-1500	462 353	8229	44 759 712	39.74
July 16-22								
1 487 047	17270	1 469 772	0	0	432 996	21 758	59 430 816	39.97
1 487 018	14 010	1 472 619	3375	-3000	445 575	20 934	59 343 616	39.91

(*) Tie-line Generation was zero throughout the weeks

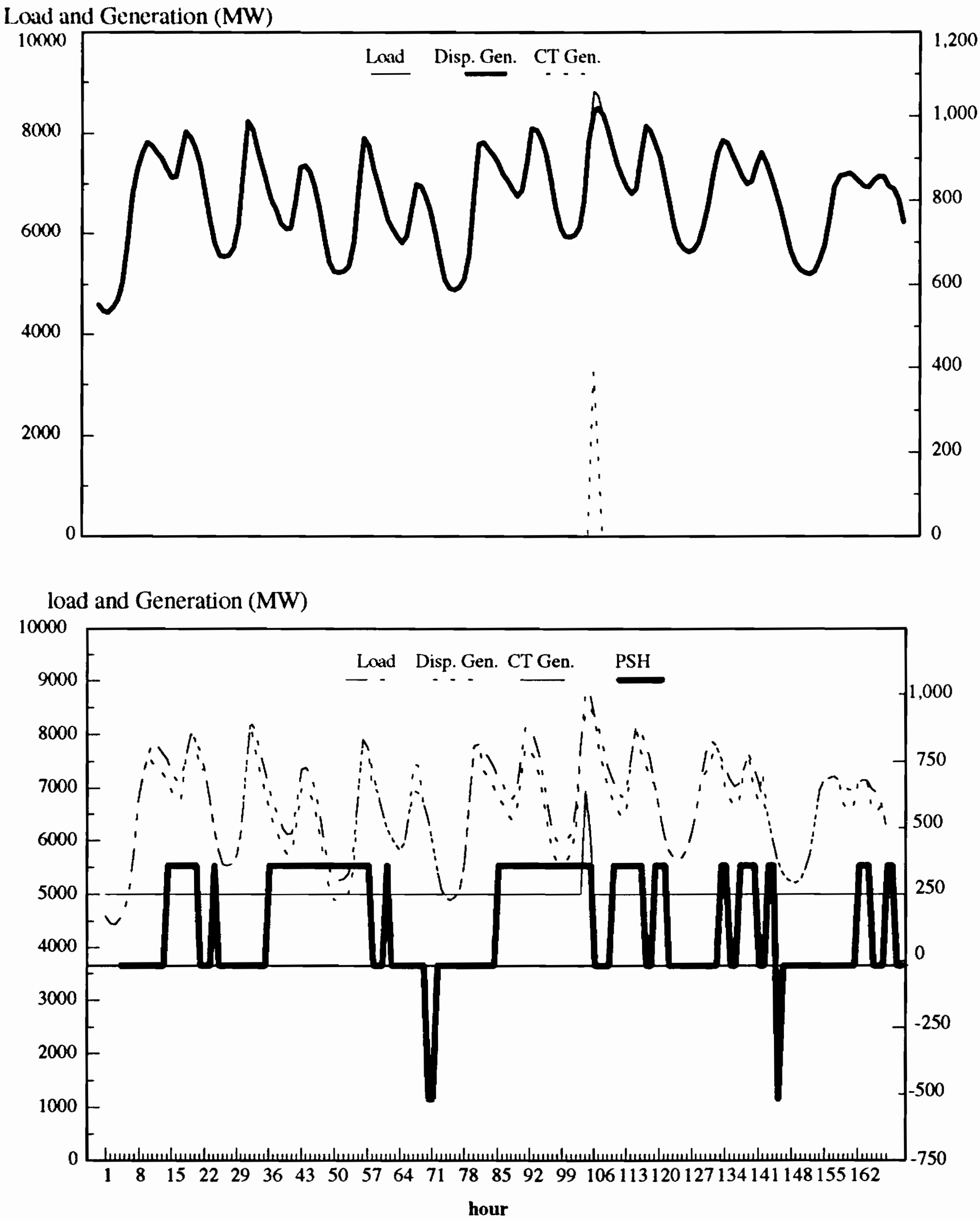
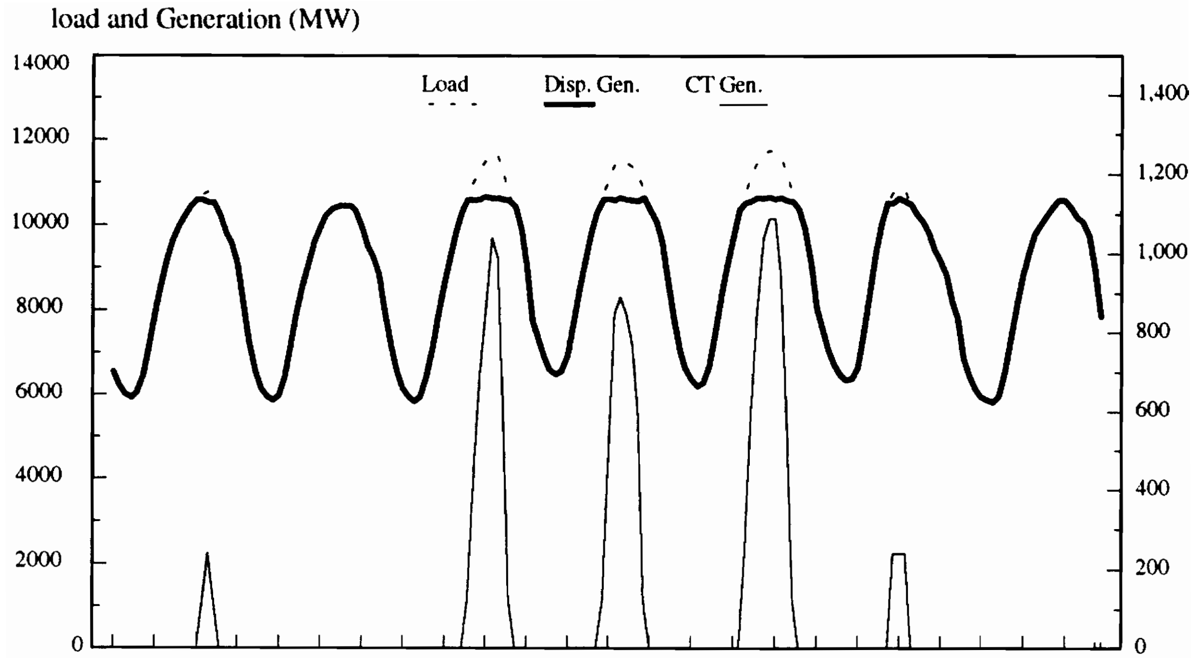


Figure 7.5 System Performance for January 21-27 (full reservoir)



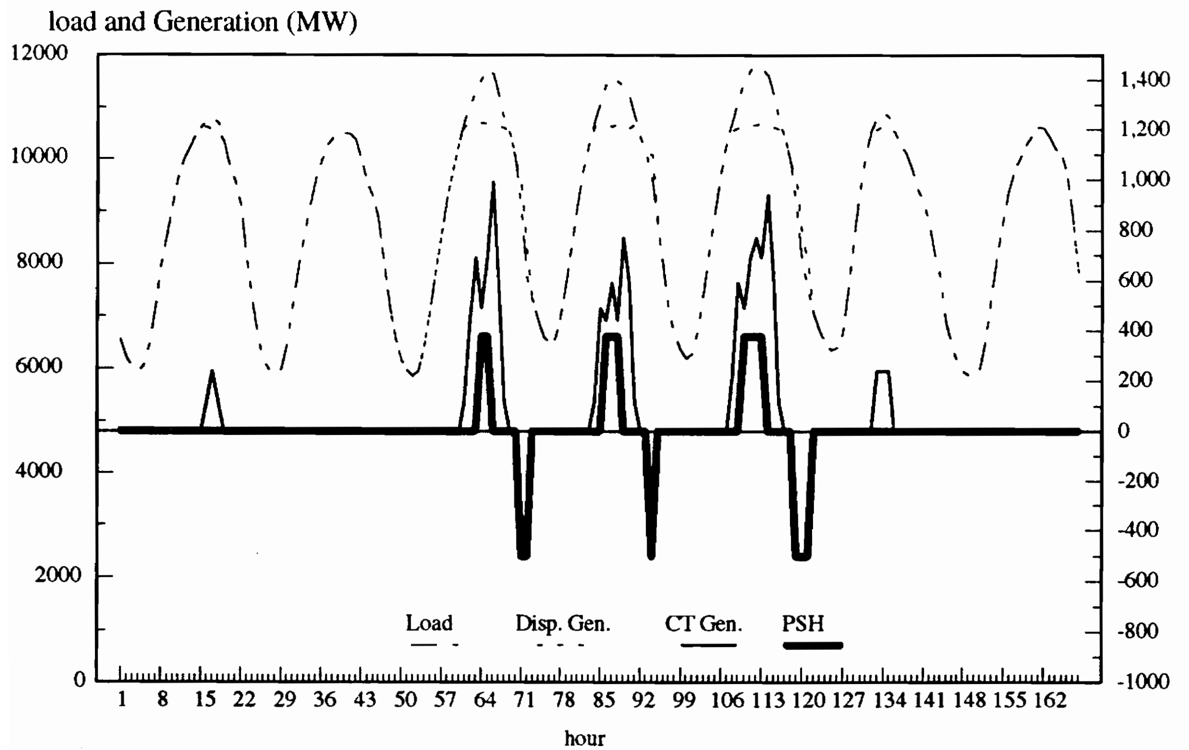


Figure 7.6 System Performance for July 16-22 (full reservoir)

Table 7.4 Daily System Operation Summary for Days in January May, July, and October

Load (MWh)	Disp. Gen (MWh)	PSH Gen (MWh)	PSH Pumping (MWh)	Hydro Gen (MWh)	Spinning Reserves (MWh)	Startup Cost ($)	Production Cost ($)	Energy Cost (mils/kWh)
		January	21(1)					
159 921	141 918	6000	- 500	12 500	46 381	0	5 801 936	36.280
		May	22					
152 541	145 666	0	- 5500	12 361	41 273	0	5 961 743	39.083
		July	16					
206 749	201 079	2250	- 9000	12422	48 248	0	8 208 459	39.703
		October	8					
155 331	141 659	5625	- 4500	12549	41 666	422	5 911 983	38.061

(1) **Zero Tie-line and CT Generation in all cases**

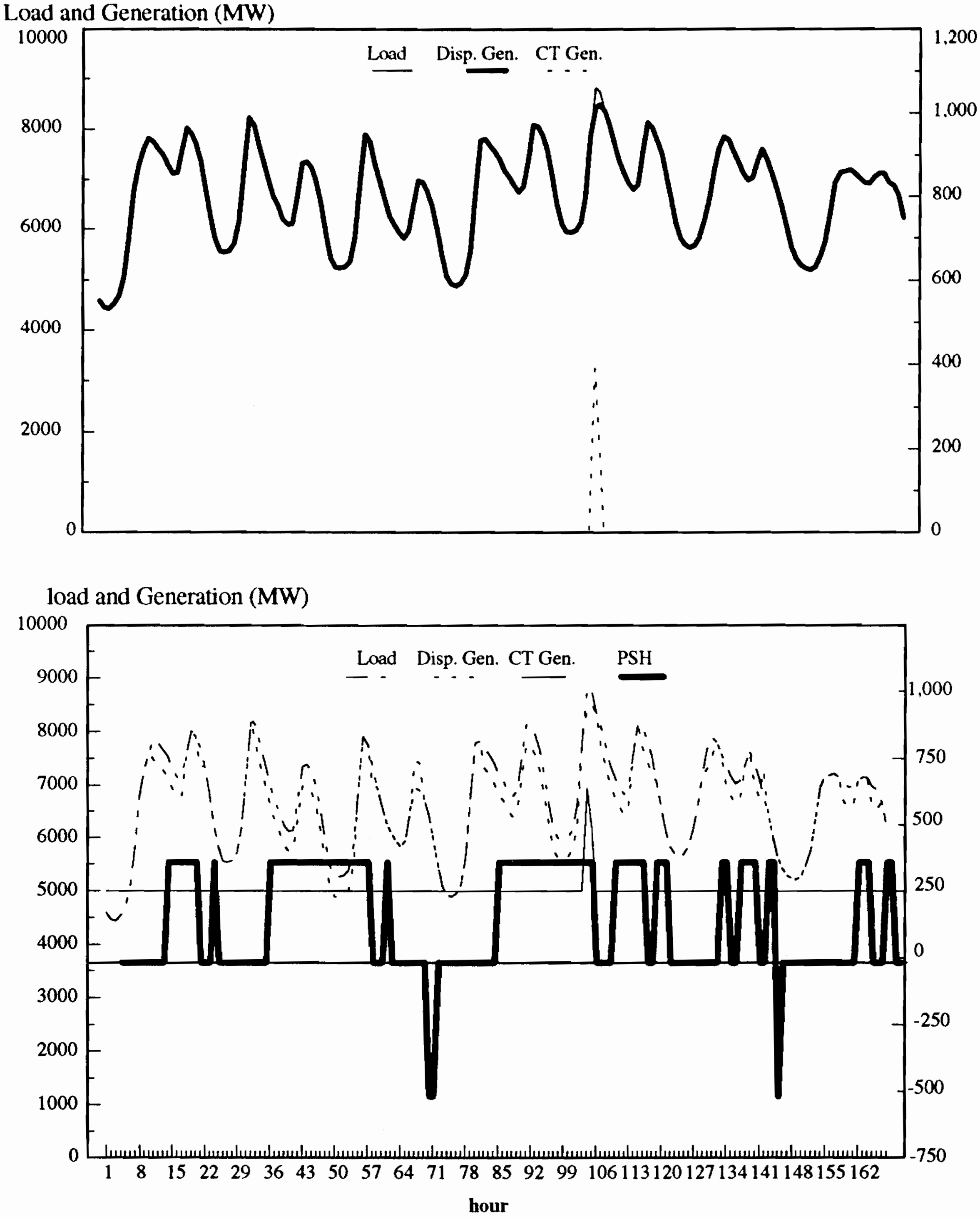


Figure 7.7 Hourly System Performance for May 22

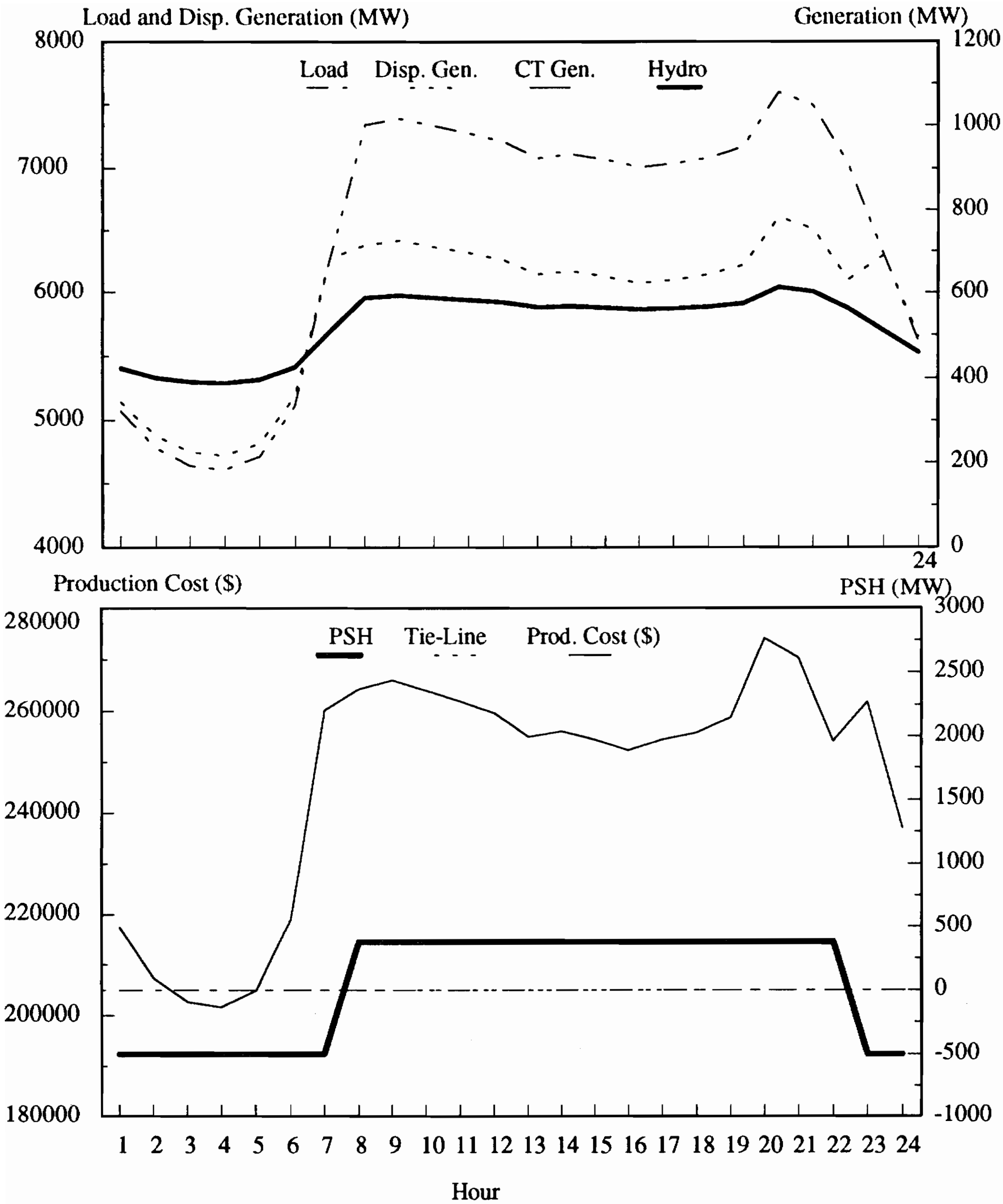


Figure 7.8 Hourly System Performance for October 8

7.4 Economic Dispatch with Hydro and PV Systems

The economic dispatch utilizes the 24-hour unit commitment schedules, hydro availability, updated load and PV power forecast. The economic dispatch solution was developed in the previous chapter. It takes into account the following:

- unit ramping rates;
- unit updated lower and upper generation limits;
- hourly hydro dispatchability;
- operating and maintenance costs for hydro, tie-line interchange, and pumped-storage;
- system losses; and
- unit commitment schedules.

Before the economic dispatch is run, the following tests are performed:

- overall system ramping capability;
- PV power output fluctuations;
- cumulative system ramping (both load variations and PV power fluctuations);
- minimum dispatchable generation; and
- maximum dispatchable generation.

Based on these tests, the following measures may be taken:

- increase tie-line interchange capacity;
- reduce pumped-storage hydro power output to absorb some of the PV power increase (the pumped-storage plant must be in generating mode); and
- reduce PV power output.

Increasing tie-line interchange is always subject to agreements between the neighboring utilities and to maximum transfer capacity. Reducing pumped-storage power output is an attractive alternative to reduce excess PV power. This is due to the high ramping rates that pumped-storage plants have. Another option to reduce problems associated with excess PV is to pump water back into the reservoir, subject to reservoir constraints and pumping capability. This option is not considered at this point.

It becomes clear that the major impact on economical and operational value of PV system is in the short-time fluctuations. By adopting the forth-mentioned measures, the level of PV penetration can be decided. The adoption of one of these measures should not be spontaneous, but should be a compromise between system security and economics. The options are, however, quite useful in exceptional operational situations.

After the dynamic dispatch is performed, additional capacity is provided by scheduling combustion turbines and increasing tie-line interchange.

To test the methodology, several study scenarios are presented in this section. Here, the PV energy value is the ratio of total production cost savings to the maximum energy produced by the PV system during sunshine time given by Equation 5.3.

The following discussion is based on maximum penetration level accepted for the day for a given fuel costs, generation mix, and PV system characteristics. In this section discussion includes impact of hydro availability, pumped-storage hydro control, tie-line capacity and PV power output control.

7.5 Impact of Hydro Dispatching on PV Penetration Levels

Figures 7.9 and 7.10 display the thermal and hydro dispatchable generation as a function of the time of the day, with and without PV system for a typical day in October and January The broken line represents the load, the thin line and thick lines represent thermal dispatchable generation and hydro generation without and without PV system, respectively. Both thermal and hydro generation increase as the load increases for both days. Hydro generation at peak loads is almost twice that at low loads. Figures 7.9 and 7.10 show how thermal (upper part) and hydro generation (lower part) changed when PV system was introduced. For Richmond (Figure 7.9), because of the early morning clouds, PV system was not generating power. However, at 10:10 a.m., PV power increased from 0 to 2400 MW in ten minutes. A part of the PV power increase was absorbed by the hydro system. The rest was absorbed by thermal dispatchable generation and tie-line interchange. On one hand, hydro generation decreased from 800 MW to zero within the ten minutes. On the other hand, thermal generation decreased by about 1600 MW to accommodate the PV power increase. Since only hydro and baseload generation are operating at the time, no other changes occurred. Then hydro and thermal generation stabilized as the PV system power output stabilized. At sunshine, the PV power output dropped slowly. Therefore, hydro and thermal dispatchable generation power output varied smoothly. Before sunshine and after sunset, hydro and thermal generation did not change. For Raleigh (Figure 7.10), the PV power output was steady until noon, but very intermittent in the afternoon. Hydro and thermal generation decreased as the PV system power output increased. At noon, and due to clouds, hydro generation increased by 500 MW to make up for the 2000 MW power drop in the PV power output. For the next hour, the PV power output was low, and hydro and thermal generation carried the load. After that, and due to moving clouds, the PV power output was fluctuating between zero and full capacity. This forced the hydro system to operate at zero and maximum dispatchable capacity. For example, at 2:10 p.m., the PV sudden increase was not absorbed by hydro and thermal generation. Therefore, tie-line interchange needed to be scheduled so as to export 500 MW. The maximum penetration levels were 2800 MW for Richmond and 1800 MW for Raleigh. However, for lower hydro availability, the penetration level was found to decrease.

Table 7.5 displays the interaction between hydro availability and penetration levels for different solar days and for a medium load day in January for zero and low hydro availability. Richmond solar data were used. The top entry of each row refers to the low availability, the bottom entry refers to zero availability. It can be seen that low hydro availability (4 percent) resulted in a 29 percent increase in the PV penetration level; under variably cloudy weather conditions (shaded area).

The quick response of the hydro unit to fluctuating PV power output stems from its fast ramping rate and zero minimum lower generation level, as opposed to thermal units. Steam units, in general, have low ramping rates and must always operate at or higher than a minimum level.

7.6 Impact of Tie-Line Interchange PV Penetration Levels

As seen in Figures 7.9 and 7.10 (Section 7.5), tie-line was scheduled to transfer excess PV power that could not absorbed by hydro and thermal generation. As tie-line capacity increases, higher penetration levels can be accepted. For example, increasing the tie-line capability from 100 MW to 400 MW resulted in 550 MW improvement in penetration level for Richmond under variably cloudy weather conditions in January (Table 7.6).

7.7 Impact of Ramping Rates On PV Penetration Levels

Table 7.7 lists the effect of ramping rates on maximum penetration levels for different load days under sunny and variably variable skies. The results are based on January and Richmond solar data. Low energy costs and low hydro availability are assumed. The increase in penetration levels (in bold) due to higher ramping rates is more significant for variably cloudy weather conditions than for sunny weather conditions.

7.8 Requirements to Increase PV Penetration Levels

Dispatching hydro plays a major role in increasing PV penetration levels. However, this option may not be available to the electric utility due to low hydro potential or dry season, as is the case on the west coast. Therefore, the utility might not fully dispatch its planned PV system as a result of dry season and/or hydro plant maintenance. To do so, the utility must devise ways to accept the entire planned capacity. This includes increasing ramping, controlling pumped storage hydro and shutting off a part of the PV system to eliminate excess power. This option works well for distributed PV systems. For example, let us assume that the first option is not possible and that hydro availability dropped to zero. What would the utility have to do to dispatch its 3500 MW PV system without hydro?. The assumed load day is medium load type, in July. For this day, the 24 hour unit commitment program predicted that no combustion turbine generation needed to be precommitted. The pumped-storage hydro, however, was committed to generate from 6.00 a.m. to 11:00 p.m. Maximum tie-line capacity was set at 500 MW. High energy costs are assumed. The following scenarios are considered: (i) operate without any control, (ii) operate with pumped-storage hydro control only, and (iii) operate with both pumped-storage and PV system control. Results shown in Table 7.8 were obtained. In case (i), only 2100 MW of PV power was accepted. In case (ii), up to 3480 MW of the PV capacity was accepted. With PV and pumped storage control (case iii), the PV system was fully accepted. For the 3490 MW level, the PV power was reduced by 8 MW. Finally, a total of 109 MWh of pumped storage generation was reduced. This was the maximum reduction for the system under study.

Table 7.5. System Operation for a Medium Weekday In January

	Rainy	Sunny	Partly Sunny	Cloudy	Variably Cloudy
PV Penetration (MW)	0 0	3 200 2 000	3 200 2 000	3 200 2 400	**2 200** **1 700**
CT Generation (MWh)	2 653 18 361	2 433 8 603	2 433 9 039	2 593 14 482	2 608 12 072
Hydro Generation (MWh)	1 270 0	1 208 0	1 265 0	1 201 0	1 287 0
PV Generation (MWh)	0 0	21 457 13 411	18 506 11 566	3 517 2 638	6 883 5 318
Production Cost ($)	2,844,340 3,900,762	2,587,819 3,126,823	2,621,337 3,172,793	2,801,560 3,585,792	2,770,126 3,443,568
PV Energy Value (mills/kWh)	na na	6.96 21.01	6.05 19.76	1.16 8.55	2.01 12.41

Note: Top (bottom) entry in each row indicates low (zero) hydro availability **Source [15]**

Table 7.6 Impact of Tie-line Capacity on PV Penetration (Richmond, Variably Cloudy Day in January)

Tie-Line Capacity (MW)	PV Penetration (MW)	PV Generation (MWh)	Daily Production Cost ($)	Production Cost Saving ($)
100	0	0	3,353,678	na
100	3231	9576	3,246,142	107,536
200	0	0	3,353,678	na
200	3381	10050	3,242,833	110,845
300	0	0	3,353,678	na
300	3581	10661	3,241,010	112,668
400	0	0	3,353,678	na
400	3781	11270	3,230,764	122,914

Table 7.7 Penetration Levels (MW) For Low and High Ramping Rates Low Hydro Availability

Load Day	Sunny	Variably Cloudy
weekday (6 950 MW)	2000 2000 **+ 0 MW**	900 2000 **+1100 MW**
weekday (9009 MW)	3200 3800 **+600 MW**	2200 3800 **+1600 MW**
weekday (10159 MW)	3500 4000 **+500 MW**	2200 4000 **+1800 MW**
weekend (7024 MW)	2000 4000 **+2000 MW**	1100 3400 **+2300 MW**

Note: Top (bottom) entry in each row indicates low (high) ramp rates

Table 7.8 System Requirements For Higher Penetration Levels (July with Variably Cloudy Day

PV Size (MW)	Daily Energy (MWh)	Dispatchable Generation (MWh)	CT Generation(MWh)	PSH Generation (MWh)	PV Generation (MWh)	Tie-Line Generation (MWh)	Start-up Cost ($)	Spinning Reserves (MWh)
0	204025	198024	1	6000	0	0	800	118575
2100	204025	190683	209	6000	6977	153	5700	125707
3000	204025	187320	336	5955	9967	448	6300	128988
3480	204025	185530	354	5891	11562	688	6400	130825
3490	204025	185486	356	5891	11594	698	6400	130868
3500	204025	185443	356	5891	11626	708	6400	130912

Table 7.8 (Cont.) Production Cost Savings and PV Energy Values (14-hour sunshine time)

PV Size (MW)	Production Cost ($)	Production Cost Saving ($)	PV Energy Value (mils/kWh)	System λ (mils/kWh)
0	19,463,312	na	na	95.40
2100	18,846,086	617,226	20.99	92.37
3000	18,580,620	882,692	21.02	91.07
3480	18,437,038	1,026,274	21.06	90.37
3490	18,433,912	1,029,410	21.07	90.35
3500	18,430,538	1,032,774	21.08	90.34

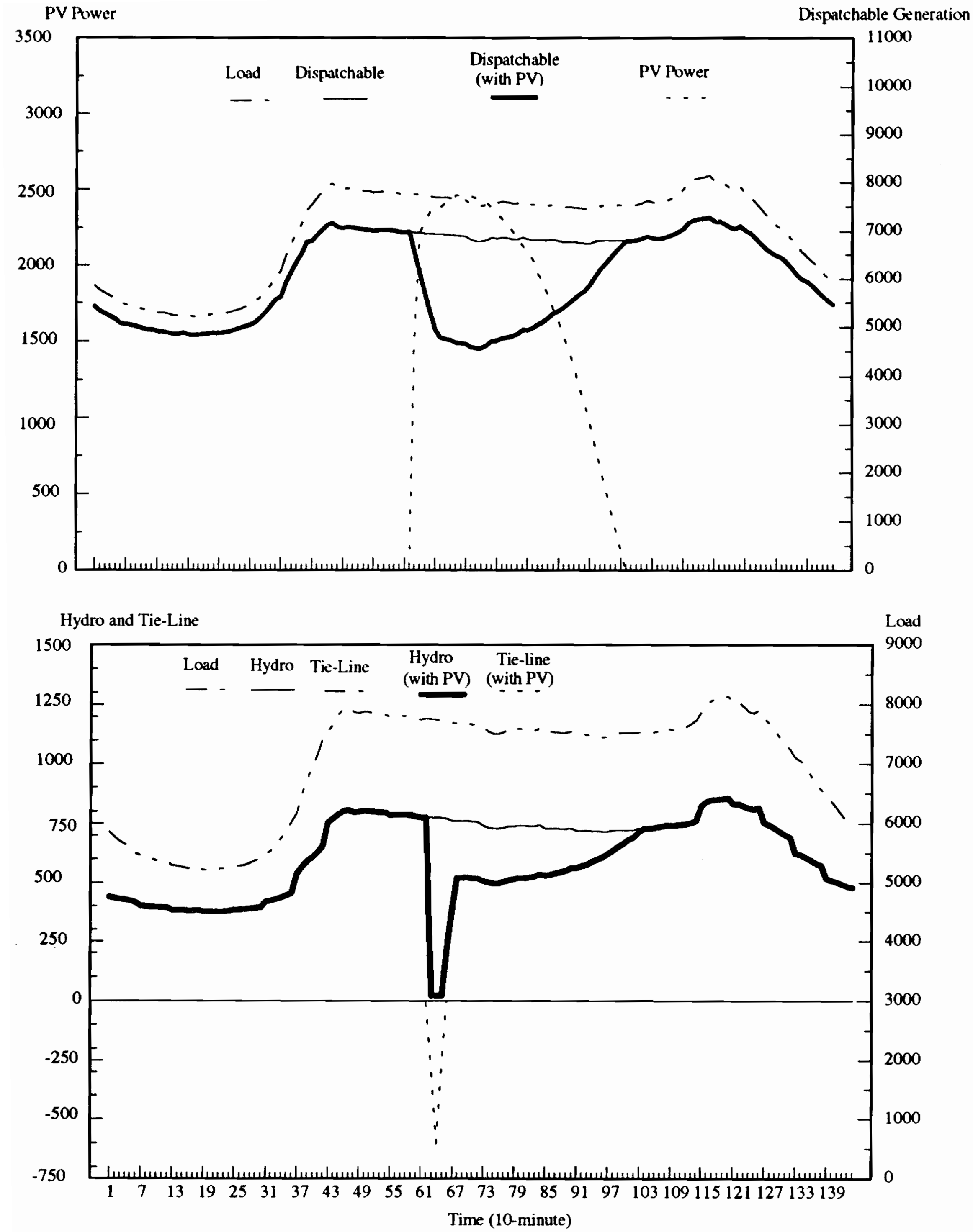


Figure 7.9 Interactions Between Hydro and PV Systems (Richmond)

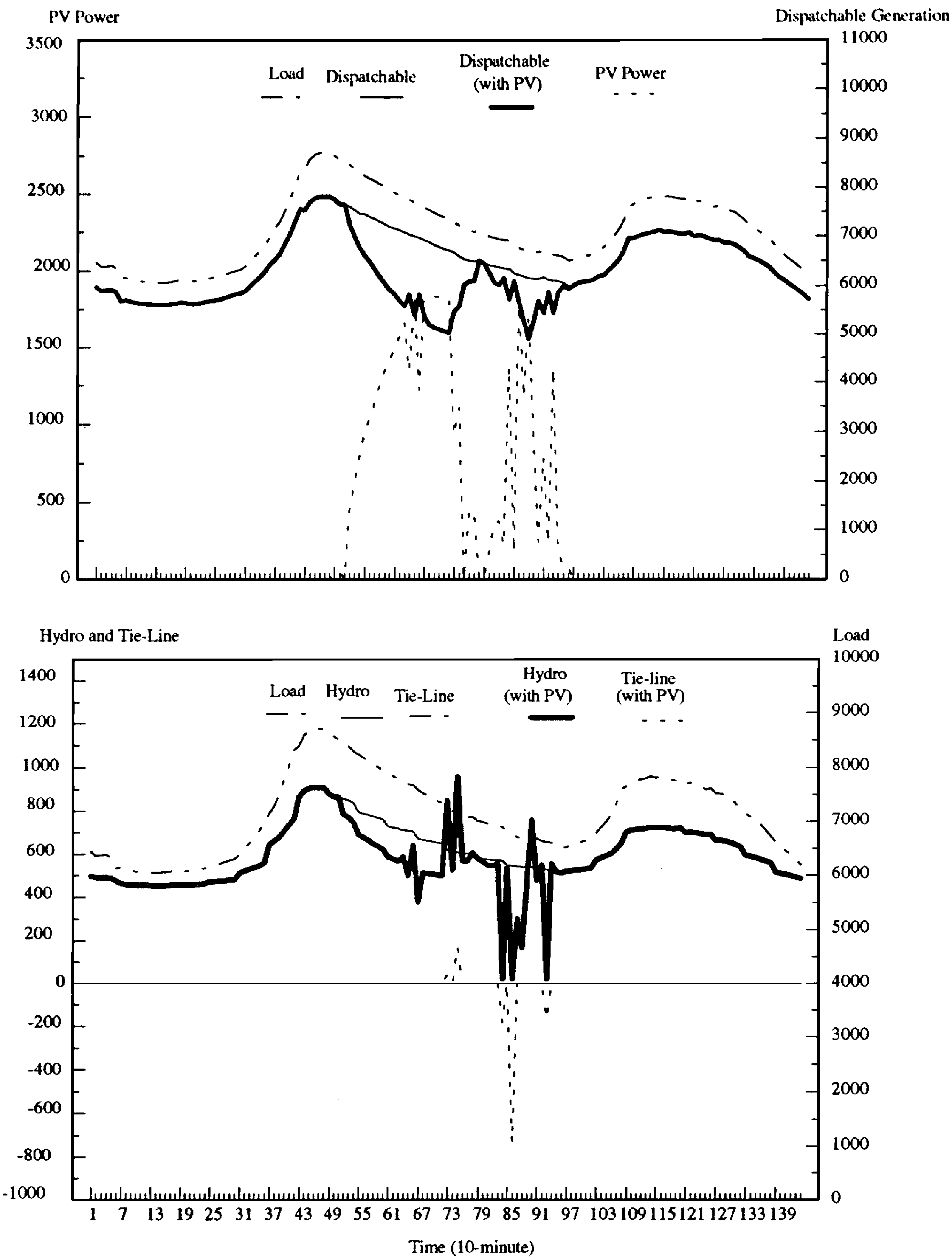


Figure 7.10 Interactions Between Hydro and PV Systems (Raleigh)

Results in Table 7.8 show also that PV intermittency can increase combustion turbine generation, tie-line energy, and startup costs. However, startup cost increased significantly.

7.9 Distributed PV System

PV system diversification offers the ultimate solution to reduce operational problems associated with PV power intermittency. Because of the geographical layout of the system, different arrays are subject to different weather patterns. In addition, because individual arrays have different solar cell technology, they respond differently to the weather changes. Knowing weather patterns and cell technology assists the dispatcher to disconnect part of the system with highest intermittency.

We have seen in a previous chapter the response of mixed technology PV system in terms of rate of changes and maximum power output. In this section, the impact of PV diversification on the electric power system operation and economics. Comparison is made with respect to combustion turbines generation and tie-line energy requirements. The daily savings and PV energy values are also compared.

The case study of Section 7.8 is considered here (same load and pumped storage hydro schedule, and zero hydro availability). However, pumped-storage and PV are not to be controlled. Here the purpose is to asses the maximum penetration level for three single and distributed PV systems. Richmond PV system is assumed to have the highest intermittency among the three stations (Richmond, VA Tech, and Raleigh). VA Tech and Raleigh do not to have the same weather conditions.

Table 7.9 lists system operation summary for the four PV systems. The maximum penetration of each station, for the day is also included. Figures 7.11 shows PV power outputs and energy interchange needed to support the PV system. In Figure 7.11, the solid line represents the power output of the distributed PV system.

The maximum penetration level for Richmond is the lowest among the four systems (2000 MW). In the distributed PV system, up to 5000 MW of PV can be accepted. Since Raleigh has the better PV performance than Richmond and Va. Tech., it required low CT generation and high tie-line energy requirements. These requirements are due to PV intermittency before noon (Figure 7.11). The distributed PV system required much less CT and tie-line support. Startup cost is a function of combustion turbine scheduling and it increased with CT generation. At the 2000 MW level, startup costs for the distributed PV system were lower than any other system configuration. The PV energy values for the 2000 MW penetration level are 21.02, 9.67, 37.89 and 23.37 mils/kWh. Raleigh performance played a significant role in reducing CT generation requirements and increasing PV energy value.

PV system may have lower energy value, but more consistency than the single-site configuration. Other advantages include low transmission addition and higher reliability.

7.10 Conclusion

In this chapter, the methodology was tested under different assumptions. The aim was to show interactions among the parameters and variables that might enhance the economical and operational value of large-scale PV applications. Parameters such as weather conditions, load shape and size, the PV system performance were found to influence the penetration level. These parameters are beyond the utility control. However, ramping rates, hydro availability and dispatchability, tie-line capacity, pumped-storage hydro scheduling and control are, the decision tools that the utility can use to enhance their penetration level.

How to use these tools and what results the utility expects must be weighted against the operational problems and economical risks. However, the biggest risk and uncertainty are in the PV system performance itself. The utility must take into consideration the breakeven capital cost and a year-around PV penetration levels. First, there is no a such "a free energy". That is, the installed capital costs for PV systems are still too high and not yet competitive with conventional energy sources. Second, PV power intermittency can make PV system fully accepted for one day and partially accepted for another. Third, having a higher penetration levels in one season than in another is not cost effective. The capital cost at which the utility can operate without losing money becomes the issue. To answer this issue, a breakeven capital cost methodology has been developed. The methodology takes into account PV system performance, prevailing weather conditions, and load day types. Sensitivity parameters such as energy costs and generation mix are also accounted for. Results for Richmond and Raleigh indicate that PV system capital cost influence the maximum penetration levels. The methodology is versatile and applicable to any electric utility interested in PV systems and in other renewable energy sources.

Table 7.9 System Performance Summary for Single and Distributed PV Systems

PV Size (MW)	Disp. Gen. (MWh)	Hydro Gen (MWh)	CT Gen. (MWh)	PV Gen. (MWh)	Tie-Line Gen. (MWh)	Start-up Cost ($)	Prod. Cost ($)	Spin. Res. (MWh)	System λ (mils/kWh)	Prod. Cost Saving ($)
Richmond										
0	198024	0	1	0	0	5000	19 467 512	118575	95.42	0
1000	194583	0	83	3322	41	7600	19 170 806	121933	93.96	296 706
2000	191031	0	219	6645	128	9900	18 879 046	125350	92.53	588 466
VA Tech										
1000	196429	0	27	1569	2	7300	19 326 946	120144	94.73	140 566
2000	194769	0	113	3138	2	11600	19 196 752	121718	94.09	270 760
2600	193762	0	165	4079	22	11700	19 113 166	122673	93.68	354 346
Raleigh										
1000	192087	0	0	5905	33	4900	18 927 796	124513	92.77	539 716
2000	186056	0	9	11809	151	5700	18 406 492	130535	90.22	1 061 020
3200	178958	0	11	18895	164	5900	17 799 788	137631	87.24	1 667 724
Distributed										
1000	194428	0	1	3599	0	5000	19 135 996	122171	93.79	331 516
2000	190822	0	1	7197	10	5000	18 813 000	125777	92.21	654 512
5000	180038	0	69	17993	-78	8100	17 891 856	136493	87.70	1 575 656

Gen.: Generation Prod.: Production Spin. Res.: Spinning Reserves

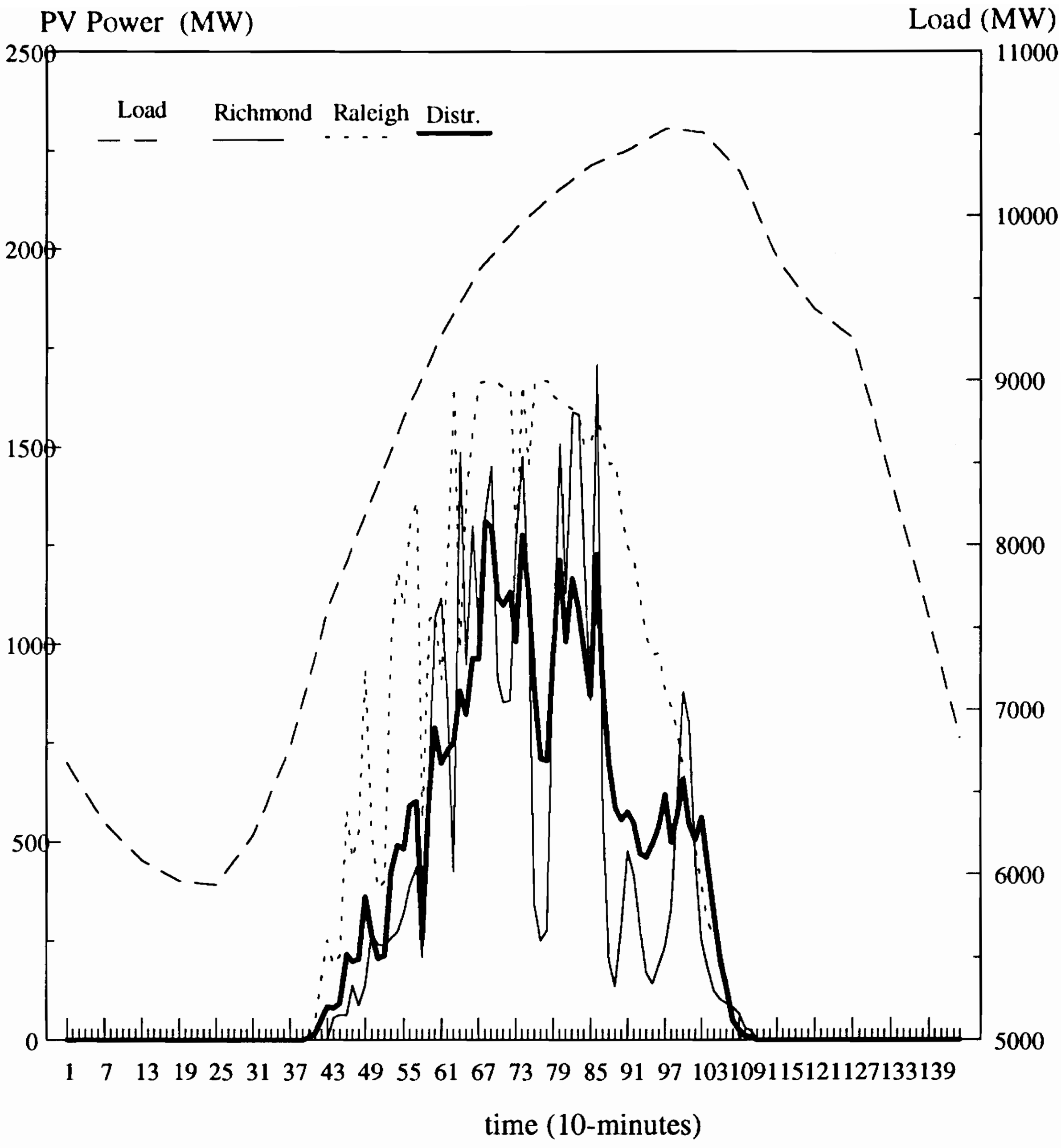


Figure 7.11 Single and Distributed PV Systems Power Output Profiles

CHAPTER 8.

BREAKEVEN CAPITAL COST ANALYSIS

8.0 Introduction

Several case studies were performed to assess the breakeven capital cost of multi-megawatt PV systems. Sensitivity analysis was carried to account for energy costs, generation mix (hydro, pumped-storage hydro, tie-line interchange), unit characteristics, and PV and pumped-storage hydro generation control. The PV system characteristics and performance were also included in the sensitivity analysis. The generating system whose characteristics are listed in Table 5.4 is used in this chapter. Table 8.1 lists 3 generation mix scenarios. The first column of Table 8.1 reflects generation mix with high nuclear generating capacity, labeled Generation Mix A. The second column represents generation mix with high coal and high hydro generating capacities, labeled Generation Mix B. The third column represents generation mix with high steam oil and hydro generating capacities. In all cases, nuclear generation cannot be cycled due to the PV system output fluctuations. The combustion turbine capacity differences are shown in Table 8.1. Table 8.2 lists low and high energy costs. High energy costs account for emission cleanup costs.

The hydro plant has the following water discharge characteristics (acre-feet/hour):

$$q(Ph) = 2260 + 10 * (Ph - 200) + 0.028 * (Ph - 200)^2 \quad \text{(acre / feet) for Ph} \geq 200 MW$$
$$q(Ph) = 260 + 10 * Ph) \quad \text{(acre / feet) for } 0 \prec Ph \prec 200 MW \qquad (8.1)$$
$$q(Ph) = 0 \quad \text{(acre / feet) for Ph} = 0$$

The pumped-storage power plant has the following characteristics:

$$q(Ph) = 250 + 2 * Ph \quad \text{(acre / feet)} \quad \text{for } 0 \leq \text{Ph} \geq 500 MW$$
$$q(Ph) = -1000 \quad \text{(acre / feet)} \quad \text{for Ph} = -500 MW \qquad (8.2)$$

Cycle Efficiency η is 0.75 [The efficiency has already been built in into the water discharge equations]. In the optimization, the power plant would pump at 500 MW and generate at 375 MW.

The economic analysis involved Richmond and Raleigh PV stations. In each case, the PV plant was assumed to consist of several distributed systems which are identical to the prototype station. The three facilities are rated at the same capacity. The maximum acceptable PV penetration was determined for each station and generation mix. The maximum available PV generation was set at 5000 MW. The penetration level for each load and prevailing weather conditions was found to depend on several parameters listed in the following. It was assumed that nuclear generation cannot be cycled due to the PV system output fluctuations

- Prevailing weather conditions;
- Daily and seasonal load and solar resource variations;
- Generation mix;
- Ramping rates;
- Energy costs;
- Hydro dispatchability and availability;
- Tie-line interchange;

- Pumped-storage hydro scheduling; and
- Pumped-storage hydro control.

Table 8.3 describes the 18 possible case studies. Each case study has its different PV system, generation mix, hydro availability, energy costs and control options. For example, in cases 1 and 2, the total nuclear, coal, steam oil, and CT generating capacities are 3000, 7500, 1200 and 1090 MW, respectively. The hydro capacity is 1200 MW. The total PSH capacity is set at zero. In cases 9 and 10, baseload generation capacities are 1800, 7500, 1200 MW for nuclear, coal and steam oil. CT and hydro generating capacities are 650 and 1800 MW, respectively. In addition, the ramping rates for CT are increased from 1 percent to 4 percent. In these two cases, high energy costs are used. Cases 13 and 14 are similar to cases 1 and 2, except pumped-storage hydro was committed by virtue of the weekly hydro-thermal coordination program.

8.1 Selection of Daily Load Patterns

The 1990 load data consists of hourly and 10-minute data for a southeastern utility. The hourly data are used for the yearly and weekly generation planning, and the 24-hour unit commitment. The 10-minute data are used by the economic dispatch program. The 10-minute time resolution is appropriate for high load variations and intermittent generation dynamics.

To represent the seasonal load variations, four days were considered: one in January, one in May, one in July and one in October. The month of May was chosen instead of April because no solar data were available for Raleigh station for that month. The selected load days correspond to the medium load of the month.

To represent the daily variations in PV system performance, five weather conditions were considered in each season. These are sunny, partly sunny, variably cloudy (intermittent), cloudy and rainy. Rainy day corresponds to zero PV power output and is used to perform the breakeven capital cost analysis.

8.2 Procedure

For each daily load type, the 24-hour unit commitment schedule was obtained assuming a zero-PV forecast. For the pumped-storage scheduling, the weekly pumped-storage optimization was performed. The 24-hour unit commitment schedule was then used by the 10-minute economic dispatch program. The maximum penetration level was based on a zero PV energy wastage.

8.2.1 Weighted Daily Production Cost Saving

For each PV penetration level, the weighted daily production cost saving (WS) for a given season, and the average daily saving (ADS) over the four seasons were computed as follows:

$$WS = \text{ndays} \times \sum_{i=1}^{4} p_i \times S_i \tag{8.3}$$

and

$$ADS = \text{average}\ (WS) \tag{8.4}$$

where

- p_i is the ratio of the number of solar days of each category to the total number of days for the month, ndays;
- S_i is the saving for the day; and
- 4 is the number of solar day categories.

Table 8.4 lists the number of days of each day category for Richmond, Raleigh and Virginia Tech PV stations. Solar day classification is based on PV capacity performance, energy performance and PV power intermittency penalty.

The intermittent penalty factor (IPF) is defined as follows:

$$\mathrm{IPF} = \sum_{t=1}^{N_p} (\mathrm{RR}_t - \mathrm{TRR}_t)^2 \qquad (8.5)$$

where

RR is the actual rate of change of PV power output,

TRR is the rate of change of PV power output under clear weather conditions.

N_p is the number of time intervals per day (N_p = 144 for 10-minute time intervals).

For example, in a sunny day, the PV system would have high peak power output for the day, produce more than 80 percent of its maximum daily generation, and have low intermmittency penalty. In an intermittent solar day (variable cloudy day), the PV system would have high peak PV power output, produce 40 to 80 percent of its daily generation, and have high intermittency penalty. Figures 8.1 and 8.2 display the selected load and PV power profiles for Richmond, and Raleigh.

During the analysis, the production cost, start-up cost, daily energy produced by each generation type, spinning reserve, and the cost of electricity were computed. The impact of system characteristics, generation mix, energy costs, and PV system performance on the PV breakeven capital cost for Richmond and Raleigh is discussed next. The PV energy value are computed for each penetration level, based on the daily production cost savings and monthly sunshine time for each season. The O&M costs for PV, pumped-storage hydro, hydro, and tie-line interchange are shown in Table 8.2. While the interactions between the generation mix, energy costs, hydro availability, ramping rates, pumped-storage hydro, tie-line characteristics, system load, and control options, in one hand and the PV penetration levels and energy values have been extensively discussed in previous chapters, they be discussed again in this chapter. In addition, energy costs from PV system, the breakeven capital cost, and PV energy values for critical penetration levels are discussed. The critical penetration levels and associated PV energy values and the breakeven capital costs will be discussed next. The following variables are considered in the discussion. Their impact on the penetration levels will identified.

- PV energy cost;
- peak load;
- solar day type;
- PV system performance;
- generation mix;
- energy costs;
- hydro availability;
- tie-line capacity.
- pumped-storage hydro scheduling and control;

8.2.2 Annual Critical Penetration Level

The annual critical penetration or simply critical penetration level is the smallest of the maximum penetration levels for all four seasons. In other words, this penetration level will be acceptable throughout the year with zero energy wastage, for each generation mix, energy costs, hydro availability and capacity, pumped-storage hydro and control combination. For each critical penetration level, there corresponds a critical breakeven capital cost. The penetration level can be either expressed in MW or in percent. In the second definition, the penetration level is defined as the ratio of the PV size (MW) to the annual peak load.

Table 8.1 Generation Mix

Technology	A Generation Mix (MW)	(%)	B Generation Mix (MW)	(%)	B Generation Mix (MW)	(%)
Nuclear	3000	20.00	1800	13.00	1800	13.00
Coal	7500	50.00	7500	54.00	6500	46.60
Steam Oil	1200	8.00	1200	8.69	2000	14.33
Oil (CT)	530	3.55	290	2.07	290	2.07
Natural Gas (CT)	560	3.75	360	2.60	360	2.60
Hydro	1200	8.00	1800	12.90	1800	12.90
Tie-line Interchange	500	3.35	500	3.58	500	3.58
PS Hydro	500	3.35	500	3.58	500	3.58
Total	14990	100.00	13950	100.00	13950	100.00

Table 8.2 Energy and O&M Costs

Technology	Energy Costs (¢/kWh)	
	Low	High
Nuclear	3.10	9.00
Coal	4.30	9.20
Large Oil	5.30	9.70
Oil (CT)	8.10	16.80
Natural Gas (CT)	6.70	14.30
Hydro	0.20	0.20
Tie-line Interchange	5.00	5.00
PS Hydro	3.50	3.50

* Based on the smallest unit and minimum loading **Source [124]**
**Based on the smallest unit and at 50% loading
PV O&M costs are 5 mills/kWh

Table 8.3 Case Studies Characteristics

Case	PV Station	Generation Mix	Hydro Avail. (%)	Tie-Line (MW)	PS Hydro (MW)	PSH Control Option	Energy Costs
1	Richmond	A	0.20	500	0	na	low
2	Raleigh	A	0.20	500	0	na	low
3	Richmond	B	0.20	500	0	na	low
4	Raleigh	B	0.20	500	0	na	low
5	Richmond	C	0.20	500	0	na	low
6	Raleigh	C	0.20	500	0	na	low
7	Richmond	A	0.20	500	0	na	high
8	Raleigh	A	0.20	500	0	na	high
9	Richmond	B	0.20	500	0	na	high
10	Raleigh	B	0.20	500	0	na	high
11	Richmond	C	0.20	500	0	na	high
12	Raleigh	C	0.20	500	0	na	high
13	Richmond	A	0.20	500	500	no	low
14	Raleigh	A	0.20	500	500	no	low
15	Richmond	B	0.20	500	500	no	high
16	Richmond	B	0.00	500	500	no	high
17	Richmond	B	0.20	250	500	no	high
18	Richmond	B	0.00	500	500	yes	high

Table 8.4 Number of Days by Solar Day Type

	Richmond (1990)				Raleigh (1986-87)			
	Jan.	May	July	Oct.	Jan.	May	July	Oct.
Sunny	7	7	3	12	11	5	3	11
Partly Sunny	12	5	9	1	3	1	4	4
Intermittent	7	10	7	6	8	7	23	7
Cloudy	5	9	12	12	9	18	1	9
Total	31	31	31	31	31	31	31	31

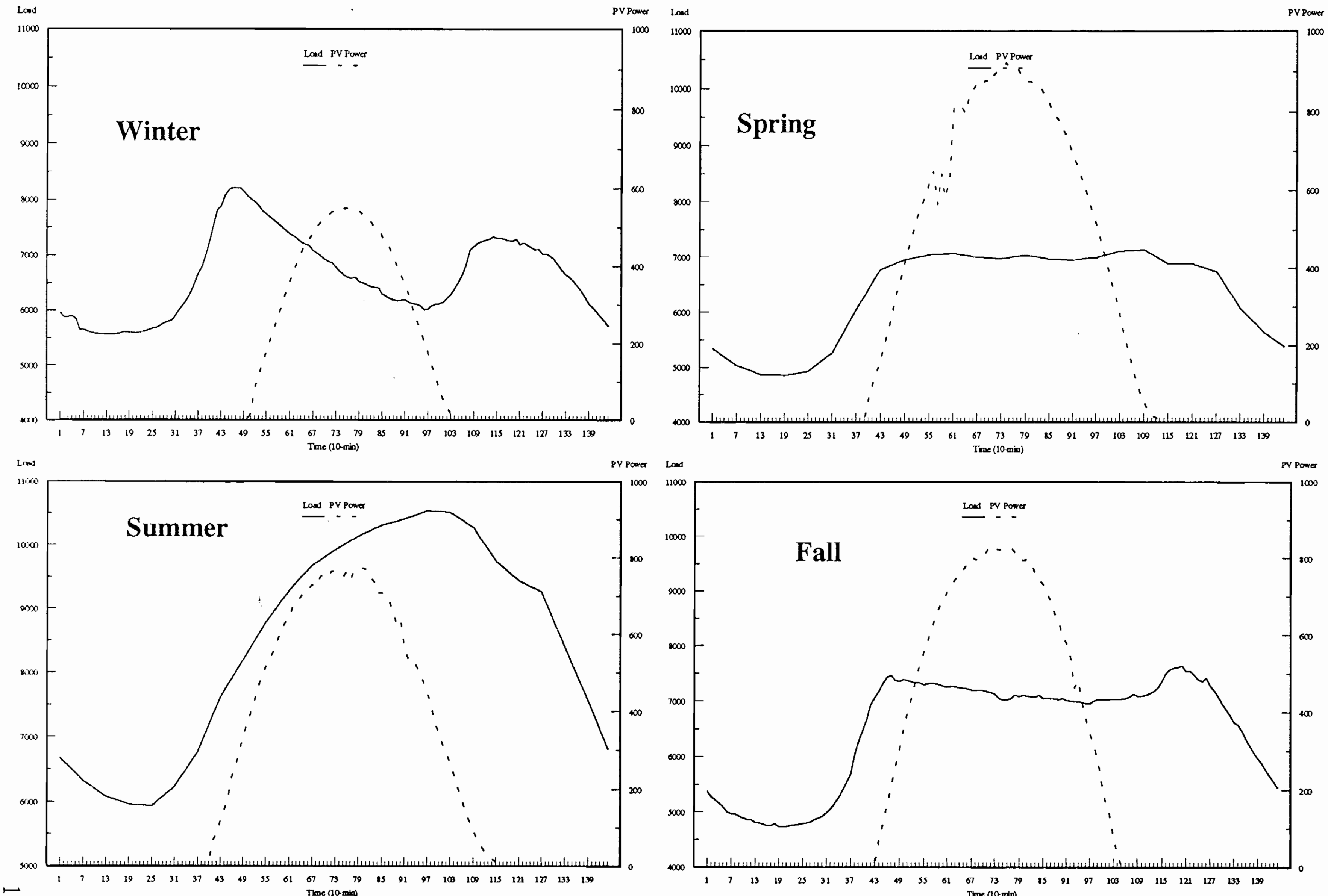


Figure 8.1 Load and PV Power Profiles (Richmond: Sunny Solar Day)

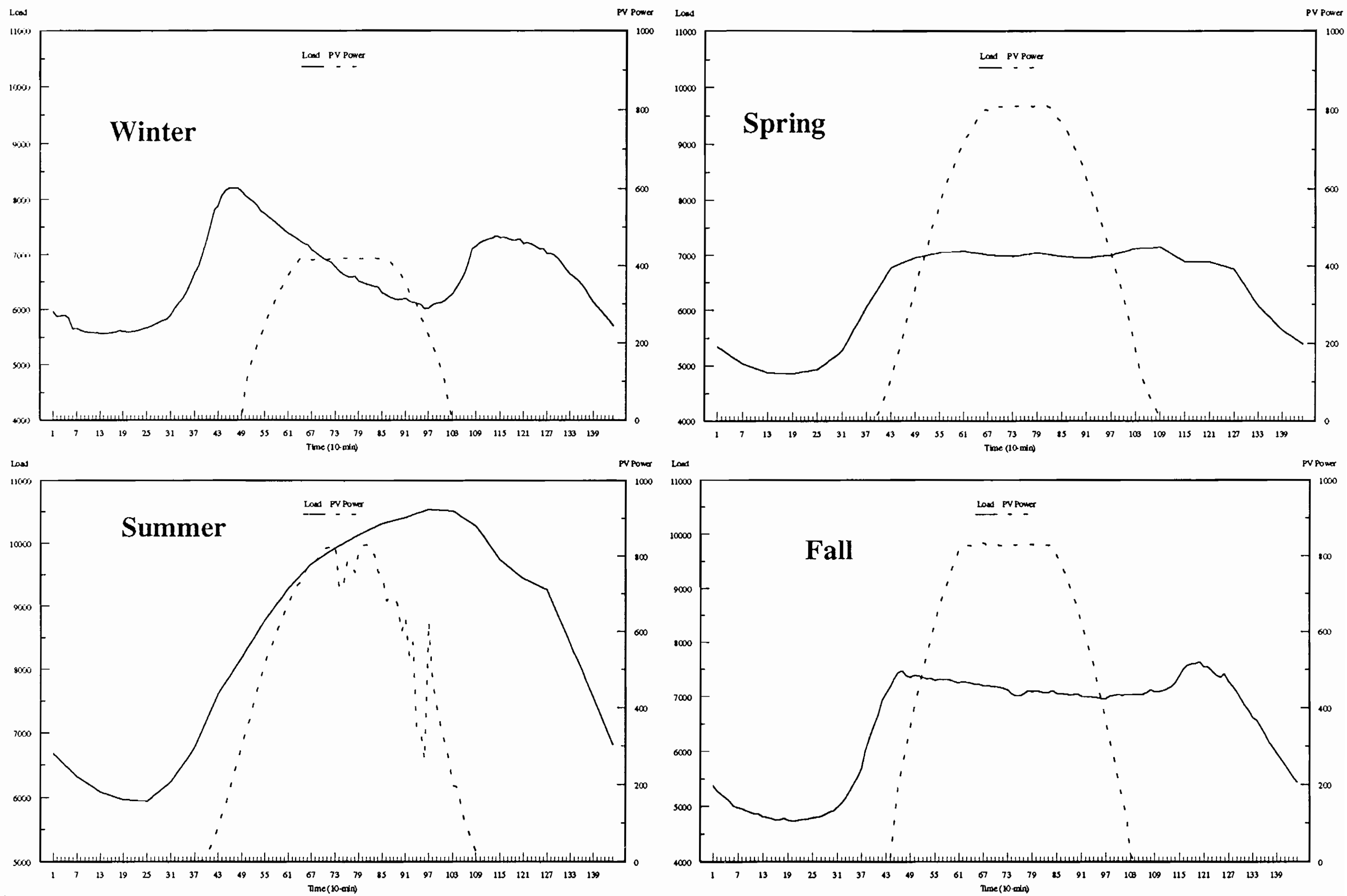


Figure 8.2 Load and PV Power Profiles (Raleigh: Sunny Solar Day)

8.2.3 Breakeven Capital Cost

The breakeven capital cost is the annual levelized cost which the utility can save per kW of PV penetration. It is based on an 8 percent interest rate and a 20 year life. Here, the breakeven capital cost is based on the daily production cost savings for all four seasons taking into account the probability of occurrence of each solar day type.

8.3 Results

Tables 8.5 through 8.12 list maximum penetration levels (column 3), daily PV generation (column 4), daily production cost savings (column 5), PV energy values (column 6), and average energy cost (column 7) for each solar day type for the four seasons. Tables 8.13 through 8.18 display same information plus pumped-storage hydro energy.

8.3.1 Peak Load

Figures 8.1 and 8.2 display the match between the peak load and peak PV power output. It can be seen that there is a better match between spring and summer peak load and peak PV power outputs. This explains why PV penetration levels were high in the spring and summer. In addition, summer load has high peak load, this improved the penetration levels. Results in Tables 8.5 through 8.20 confirm this observation.

8.3.2 Solar Day Types

For the cloudy days, the PV available capacity was too low and up to 5000 MW penetration levels were accepted by the system, in any of the four seasons. However, the peak PV power output for the day had reached 20 percent of the PV system rated capacity. For cloudy days, production cost savings were the lowest among other solar day types. The PV energy values, were therefore the lowest. Similarly, in partly sunny days, the system accepted more PV power than in sunny days. For sunny days, the PV penetration levels were high and they varied from one season to another. In sunny days, the PV power system acted as a baseload generation system. The penetration level was therefore a function of the baseload size. For intermittent solar days, the PV penetration levels were, in general, lower than any other solar days for spring and summer, but higher than that for sunny in winter and fall. This was due to high PV power fluctuations in the spring and summer seasons and low fluctuations in winter and fall.

8.3.3 PV System Performance

In Appendix A, the annual energy produced by Richmond, VA Tech., Raleigh PV, and the distributed PV systems are discussed (Table A.1). As seen in Table A.1, Raleigh PV stations produced more energy than Richmond did during the months of January, July and October and less energy in May. The daily available capacity was also higher in Raleigh than in Richmond. Under the same generation mix and energy costs, the penetration levels for Raleigh were always lower than those for Richmond, except for May, where the penetration levels are significantly close. For example, examining the lower part of Tables 8.5 and 8.6, the same penetration level produced more energy in Raleigh than in Richmond during the month of October. Examining Tables 8.7 and 8.8 indicates that penetration levels were higher in Raleigh than in Richmond during the month of May.

8.3.4 Generation Mix

Examining Tables 8.5 and 8.7 reveals that decreasing nuclear capacity and increasing hydro capacity from 1200 to 1800 MW has significantly improved penetration levels for Richmond PV system for two reasons:

1. As nuclear capacity was reduced from 3000 MW to 1800 MW, more coal and oil baseload generations were dispatched to meet load plus losses. Thus higher generation is made available for cycling due to PV power fluctuations.

2. As seen in Chapter 8, hydro plays a significant role in increasing PV penetration levels. The 600 MW increase in hydro would explain in the PV penetration levels.

Similarly, for Raleigh, PV penetration levels increased as more hydro and less nuclear capacities were made available.

8.3.5 Energy Costs

High energy costs, new unit commitment schedules were obtained. Upon examining commitment schedules for cases 1& 7, it was found that while nuclear units were committed throughout the 24-hour period, they were running at lower capacity in the high energy cost case. Thus coal and steam oil units were committed over longer times to meet load plus losses. This made more baseload generation, and thus higher ramping rates. This resulted in higher penetration levels.

For Cases 1 and 7 (Tables 8.5 and 8.9), high nuclear capacity was assumed. For these two cases, PV penetration levels increased for January, May and October, but decreased for July. Similarly for Raleigh (Cases 2 and 8), the penetration levels increased for the same seasons and decreased in July.

For Cases 3 and 9 (Tables 8.7 and 8.11) penetration levels increased slightly. For some solar days, no increase was observed. For intermittent solar days, however, an increase of up to 400 MW was obtained. For Raleigh (Tables 8.6 and 8.10), up to 300 MW increase was registered. For the summer, however, penetration levels decreased by up to 1000 MW for

Table 8.5 PV Energy Values for Case 1

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	37.09
	Sunny	1300	4067	133625	11.17	36.23
	Partly Sunny	1600	3971	128945	8.76	36.25
	Intermittent	1500	3165	104277	7.56	36.42
	Cloudy	5000	2555	81505	1.77	36.56
May	Rainy	0	0	0	na	36.39
	Sunny	1700	11765	363132	14.34	33.98
	Partly Sunny	2000	10743	328857	11.04	34.20
	Intermittent	1700	8970	275224	10.87	34.56
	Cloudy	3600	3495	110149	2.05	35.66
July	Rainy	0	0	0	na	39.47
	Sunny	4400	26176	863913	13.93	35.22
	Partly Sunny	3000	9149	308019	7.28	37.96
	Intermittent	3000	9967	321004	7.59	37.90
	Cloudy	5000	2595	89910	1.28	39.03
October	Rainy	0	0	0	na	36.64
	Sunny	1400	8048	241099	17.22	35.07
	Partly Sunny	1400	5778	173883	12.42	35.50
	Intermittent	1500	6366	189349	12.62	35.41
	Cloudy	5000	3721	110576	2.21	35.93

Table 8.6 PV Energy Values for Case 2

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	37.09
	Sunny	700	4116	135500	21.04	36.22
	Partly Sunny	1000	3968	124371	13.52	36.29
	Intermittent	700	2298	73319	11.38	36.62
	Cloudy	1600	2540	77400	5.26	36.59
May	Rainy	0	0	0	na	36.39
	Sunny	1900	11721	363950	12.86	33.97
	Partly Sunny	1900	7288	227835	8.05	34.88
	Intermittent	1900	8016	242991	8.58	34.78
	Cloudy	3200	4791	150732	3.16	35.39
July	Rainy	0	0	0	na	39.47
	Sunny	4000	23711	777379	13.78	35.65
	Partly Sunny	4000	18027	579471	10.27	36.62
	Intermittent	2600	11900	392046	10.69	37.55
	Cloudy	3600	19187	624158	12.30	36.41
October	Rainy	0	0	0	na	36.64
	Sunny	1400	8579	260156	18.58	34.94
	Partly Sunny	1400	5774	174242	12.45	35.50
	Intermittent	1500	6181	185017	12.33	35.44
	Cloudy	1700	3320	102820	6.05	35.98

Table 8.7 PV Energy Values for Case 3

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	39.12
	Sunny	3800	11889	384077	10.99	36.68
	Partly Sunny	4200	10424	334165	8.65	36.99
	Intermittent	3600	7595	239828	7.24	37.60
	Cloudy	5000	2555	84631	1.84	38.58
May	Rainy	0	0	0	na	38.89
	Sunny	2400	16609	535891	14.99	35.36
	Partly Sunny	2800	15040	484012	11.60	35.70
	Intermittent	2400	12663	408256	11.42	36.20
	Cloudy	4400	4272	141218	2.15	37.97
July	Rainy	0	0	0	na	40.78
	Sunny	5000	29746	1002960	14.23	35.85
	Partly Sunny	2800	8539	298654	7.56	39.32
	Intermittent	3000	9967	337888	7.99	39.13
	Cloudy	5000	2595	93941	1.33	40.32
October	Rainy	0	0	0	na	39.04
	Sunny	2600	14946	476145	18.31	35.96
	Partly Sunny	2000	8254	262622	13.13	37.35
	Intermittent	2800	11884	376790	13.46	36.61
	Cloudy	5000	3721	122876	2.46	38.25

Table 8.8 PV Energy Values for Case 4

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	39.12
	Sunny	2200	12934	415357	20.52	36.48
	Partly Sunny	2400	9523	308451	13.97	37.17
	Intermittent	1400	4596	150507	11.69	38.17
	Cloudy	3800	6032	196688	5.63	37.87
May	Rainy	0	0	0	na	38.90
	Sunny	2600	16040	515724	13.31	35.49
	Partly Sunny	2800	10740	350468	8.40	36.59
	Intermittent	2600	10969	344322	8.89	36.63
	Cloudy	4400	6587	214744	3.28	37.48
July	Rainy	0	0	0	na	40.78
	Sunny	4800	28453	955744	14.12	36.09
	Partly Sunny	4600	20731	688642	10.62	37.40
	Intermittent	2600	11900	409593	11.17	38.78
	Cloudy	3200	17055	584654	12.96	37.92
October	Rainy	0	0	0	na	39.04
	Sunny	2600	15933	509909	19.61	35.74
	Partly Sunny	2600	10723	342765	13.18	36.83
	Intermittent	2800	11538	372884	13.32	36.64
	Cloudy	2600	5078	165651	6.37	37.97

Table 8.9 PV Energy Values for Case 7

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	**Rainy**	0	0	0	na	89.30
	Sunny	1800	5632	330962	19.99	87.13
	Partly Sunny	2200	5460	309283	15.28	87.23
	Intermittent	2000	4220	249574	13.56	87.62
	Cloudy	5000	2555	140896	3.06	88.28
May	**Rainy**	0	0	0	na	88.57
	Sunny	1900	13149	875484	30.92	82.63
	Partly Sunny	2200	11817	789969	24.10	83.18
	Intermittent	2000	10553	696491	23.37	83.78
	Cloudy	3800	3689	272193	4.81	86.76
July	**Rainy**	0	0	0	na	92.26
	Sunny	3200	19037	1441840	31.96	85.05
	Partly Sunny	2200	6710	517616	16.69	89.70
	Intermittent	3000	9967	753904	17.82	88.51
	Cloudy	5000	2595	216144	3.07	91.20
October	**Rainy**	0	0	0	na	88.88
	Sunny	1800	10348	668154	37.12	84.44
	Partly Sunny	1800	7428	455244	25.29	85.87
	Intermittent	2000	8488	557965	27.90	85.17
	Cloudy	5000	3721	272953	5.46	87.09

Table 8.10 PV Energy Values for Case 8

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	89.31
	Sunny	1000	5879	357701	38.88	86.97
	Partly Sunny	1200	4761	304466	27.58	87.29
	Intermittent	1000	3283	224501	24.40	87.86
	Cloudy	2000	3175	216999	11.79	87.86
May	Rainy	0	0	0	na	88.57
	Sunny	2200	13572	877495	26.77	82.59
	Partly Sunny	2000	7672	556729	18.68	84.87
	Intermittent	2200	9281	627610	19.15	84.28
	Cloudy	3400	5090	366315	7.23	86.13
July	Rainy	0	0	0	na	92.26
	Sunny	3000	17783	1343232	31.75	85.58
	Partly Sunny	3000	13520	1002560	23.70	87.27
	Intermittent	1900	8696	687120	25.65	88.86
	Cloudy	3000	15989	1208544	28.57	86.26
October	Rainy	0	0	0	na	88.89
	Sunny	1600	9805	641059	40.07	84.62
	Partly Sunny	1700	7011	455021	26.77	85.85
	Intermittent	1900	7829	535290	28.17	85.35
	Cloudy	2000	3906	285018	14.25	87.02

Table 8.11 PV Energy Values for Case 9

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	na	90.83
	Sunny	3600	11263	798540	24.11	85.73
	Partly Sunny	4000	9927	692719	18.82	86.38
	Intermittent	3600	7595	551544	16.65	87.27
	Cloudy	5000	2555	204769	4.45	89.54
May	Rainy	0	0	0	na	89.46
	Sunny	3200	22146	1664866	34.92	78.46
	Partly Sunny	3800	20412	1537697	27.16	79.30
	Intermittent	2800	14770	1152387	27.62	81.83
	Cloudy	4600	4466	356510	5.20	87.10
July	Rainy	0	0	0	na	92.58
	Sunny	5000	29746	2377285	33.72	80.87
	Partly Sunny	2800	8539	704976	17.86	89.11
	Intermittent	3000	9967	834576	19.73	88.45
	Cloudy	5500	2595	225136	3.20	91.61
October	Rainy	0	0	0	na	90.32
	Sunny	2800	16096	1181407	42.19	82.62
	Partly Sunny	2000	8254	629101	31.46	86.25
	Intermittent	3200	13581	989567	30.92	83.83
	Cloudy	5000	3721	296107	5.92	88.39

Table 8.12 PV Energy Values for Case 10

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	**Rainy**	0	0	0	na	90.83
	Sunny	3600	11263	798540	24.11	85.73
	Partly Sunny	4000	9927	692719	18.82	86.38
	Intermittent	3600	7595	551544	16.65	87.27
	Cloudy	5000	2555	204769	4.45	89.54
May	**Rainy**	0	0	0	na	89.46
	Sunny	3200	22146	1664866	34.92	78.46
	Partly Sunny	3800	20412	1537697	27.16	79.30
	Intermittent	2800	14770	1152387	27.62	81.83
	Cloudy	4600	4466	356510	5.20	87.10
July	**Rainy**	0	0	0	na	92.58
	Sunny	5000	29746	2377285	33.72	80.87
	Partly Sunny	2800	8539	704976	17.86	89.11
	Intermittent	3000	9967	834576	19.73	88.45
	Cloudy	4400	2284	198800	3.20	91.61
October	**Rainy**	0	0	0	na	90.32
	Sunny	2800	16096	1181407	42.19	82.62
	Partly Sunny	2000	8254	629101	31.46	86.25
	Intermittent	3200	13581	989567	30.92	83.83
	Cloudy	5000	3721	296107	5.92	88.39

Table 8.13 PV Energy Values for Case 13

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	0	na	38.91
	Sunny	5000	15643	0	514524	11.19	36.53
	Partly Sunny	5000	12409	0	406164	8.83	37.03
	Intermittent	5000	10549	0	347070	7.55	37.30
	Cloudy	5000	2555	0	85697	1.86	38.51
May	Rainy	0	0	0	0	na	39.64
	Sunny	3200	22146	0	666520	13.98	35.41
	Partiy Sunny	4000	21486	0	650369	10.91	35.51
	Intermittent	3200	16885	0	516875	10.84	36.36
	Cloudy	5000	4854	0	154192	2.07	38.66
July	Rainy	0	0	6000	0	na	39.58
	Sunny	5000	29746	6000	984364	13.96	34.96
	Partly Sunny	2400	7320	6000	245059	7.24	38.44
	Intermittent	3600	11960	6000	400955	7.90	37.70
	Cloudy	5000	2595	6000	91515	1.30	39.16
October	Rainy	0	0	0	0	na	39.86
	Sunny	3600	20695	0	634436	17.62	35.89
	Partly Sunny	2800	11555	0	347892	12.42	37.68
	Intermittent	4000	16977	0	523602	13.09	36.58
	Cloudy	5000	3721	0	118911	2.38	39.12

Table 8.14 PV Energy Values for Case 14

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	0	na	38.91
	Sunny	4400	25869	0	819539	20.25	35.11
	Partly Sunny	4600	18252	0	585596	13.84	36.20
	Intermittent	2000	6566	0	218017	11.85	37.90
	Cloudy	5000	7939	0	257247	5.59	37.72
May	Rainy	0	0	0	0	na	39.64
	Sunny	3800	23443	0	711061	12.56	35.12
	Partly Sunny	3200	12275	0	384318	8.06	37.20
	Intermittent	3400	14344	0	439860	8.68	36.85
	Cloudy	5000	7486	0	230540	3.09	38.18
July	Rainy	0	0	6000	0	na	39.58
	Sunny	2800	16598	6000	562718	14.25	36.94
	Partly Sunny	5000	22534	6000	730602	10.36	36.15
	Intermittent	3000	13731	6000	474846	11.23	37.36
	Cloudy	4000	21319	6000	714189	12.66	36.23
October	Rainy	0	0	0	0	na	39.86
	Sunny	3600	22061	0	680598	18.91	35.60
	Partly Sunny	3600	14848	0	456315	12.68	37.01
	Intermittent	3800	15658	0	490643	12.91	36.80
	Cloudy	3600	7031	0	223378	6.20	38.46

Table 8.15 PV Energy Values for Case 15

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	0	na	92.01
	Sunny	5000	15643	0	1175741	25.56	85.13
	Partly Sunny	5000	12409	0	926811	20.15	86.58
	Intermittent	5000	10549	0	804079	17.48	87.29
	Cloudy	5000	2555	0	195312	4.25	90.87
May	Rainy	0	0	0	0	na	91.67
	Sunny	4400	30451	0	2096955	31.99	78.87
	Partly Sunny	5000	26857	0	1897635	25.47	80.10
	Intermittent	3600	18995	0	1416171	26.40	83.06
	Cloudy	5000	4854	0	368087	4.94	89.44
July	Rainy	0	0	6000	0	na	90.27
	Sunny	5000	29746	6000	2398087	34.02	78.52
	Partly Sunny	3600	10979	6000	855264	16.85	86.07
	Intermittent	3800	12625	6000	1048192	19.56	85.13
	Cloudy	5000	2595	6000	218384	3.10	89.21
October	Rainy	0	0	0	0	na	91.83
	Sunny	5000	28743	0	2045395	40.91	79.55
	Partly Sunny	2800	11555	0	838097	29.93	86.82
	Intermittent	4200	17825	0	1303485	31.04	84.02
	Cloudy	5000	3721	0	279543	5.59	90.16

Table 8.16 PV Energy Values for Case 16

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy ((MWh))	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	**Rainy**	0	0	0	0	na	97.91
	Sunny	5000	15643	0	1275140	27.72	90.45
	Partly Sunny	4200	10424	0	858063	22.08	92.92
	Intermittent	3200	6751	0	561569	19.08	94.63
	Cloudy	5000	2555	0	212060	4.61	96.67
May	**Rainy**	0	0	0	0	na	98.32
	Sunny	4200	29067	0	2334332	37.30	84.13
	Partly Sunny	5000	26857	0	2165636	29.07	85.15
	Intermittent	2200	11608	0	968852	29.56	92.43
	Cloudy	3800	3689	0	310123	5.48	96.44
July	**Rainy**	0	0	6000	0	na	95.42
	Sunny	5000	29746	6000	2574256	36.51	82.80
	Partly Sunny	2400	7320	6000	653600	19.31	92.21
	Intermittent	2000	6645	6000	588432	20.87	92.53
	Cloudy	5000	2595	6000	240016	3.40	94.24
October	**Rainy**	0	0	0	0	na	98.15
	Sunny	5000	28743	0	2326642	46.53	84.29
	Partly Sunny	1800	7428	0	614011	34.11	94.49
	Intermittent	2400	10186	0	851341	35.47	93.08
	Cloudy	5000	3721	0	313453	6.27	96.29

Table 8.17 PV Energy Values for Case 17

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy (MWh)	Savings $	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	0	na	92.01
	Sunny	5000	15643	0	1175741	25.56	85.13
	Partly Sunny	5000	12409	0	926811	20.15	86.58
	Intermittent	4800	10127	0	773981	17.53	87.43
	Cloudy	5000	2555	0	195312	4.25	90.87
May	Rainy	0	0	0	0	na	91.67
	Sunny	4200	29076	0	2023962	32.34	79.28
	Partly Sunny	4800	25783	0	1845705	25.81	80.41
	Intermittent	3200	16885	0	1257248	26.37	84.03
	Cloudy	5000	4854	0	368087	4.94	89.44
July	Rainy	0	0	6000	0	na	90.27
	Sunny	5000	29746	6000	2398087	34.02	78.52
	Partly Sunny	3200	9759	6000	762960	16.91	80.41
	Intermittent	3200	10631	6000	882496	19.56	85.94
	Cloudy	5000	2595	6000	218384	3.10	89.21
October	Rainy	0	0	0	0	na	91.83
	Sunny	5000	28743	0	2045395	40.91	79.55
	Partly Sunny	2400	9904	0	722973	30.12	87.49
	Intermittent	3600	15279	0	1134372	31.51	85.04
	Cloudy	5000	3721	0	279543	5.59	90.16

Table 8.18 PV Energy Values for Case 18

Month	Solar Day	PV Size (MW)	PV Energy (MWh)	PSH Energy (MWh)	Savings ($)	PVEV (mils/kWh)	Energy Cost (mils/kWh)
January	Rainy	0	0	0	0	na	97.91
	Sunny	5000	15643	0	1275138	27.72	90.45
	Partly Sunny	4200	10424	0	853060	22.08	92.92
	Intermittent	3200	6751	0	561570	19.08	94.62
	Cloudy	5000	2555	0	212056	4.61	96.67
May	Rainy	0	0	0	0	na	98.32
	Sunny	4200	29067	0	2334339	37.30	84.12
	Partly Sunny	5000	26857	0	2165639	29.07	85.15
	Intermittent	2200	11608	0	968860	29.56	92.43
	Cloudy	3800	3689	0	310119	5.48	96.43
July	Rainy	0	0	6000	0	na	95.42
	Sunny	5000	29746	6000	2574412	36.52	82.80
	Partly Sunny	3000	9150	5915	804666	19.02	91.47
	Intermittent	3400	11296	5901	1004130	20.95	90.50
	Cloudy	5000	2595	6000	240038	3.40	94.24
October	Rainy	0	0	0	0	na	98.15
	Sunny	5000	28743	0	2326651	46.53	84.29
	Partly Sunny	1800	7428	0	614018	34.11	94.49
	Intermittent	2400	10186	0	851344	35.47	93.08
	Cloudy	5000	3721	0	313465	6.27	96.28

sunny days. For cases 4 and 10, a significant increase in penetration level was obtained. The increase reached 2200 MW in January and 400 MW in July and October.

8.3.5 Pumped-Storage Hydro Scheduling

In cases 13 through 18, pumped-storage hydro power plant was pumping in January, May, and October, and generating in July. This lead to an increase in the load demand in January, May, and October and load demand reduction in July. This resulted in higher baseload generation in the former months and lower baseload generation in the latter. Compared to case 1, more units were committed in case 13. Therefore, higher available ramping capacity existed and more PV was accepted. A very significant increase in PV penetration level was observed for intermittent solar days (Tables 8.5 and 8.13). Similarly for Raleigh, (Tables 8.6 and 8.14), PV penetration levels increased substantially. In summary, pumping in low load periods and generating in high load periods is a common practice and this could help to narrow the gap between winter low penetration levels and summer high penetration levels. This option is worth considering, in particular when fluctuating PV power output exists.

8.3.7 Hydro availability

The following discussion is based on cases 15 and 16 (Tables 8.15 and 8.16). As hydro availability was reduced from 20 percent to 0 percent, penetration levels decreased for partly sunny and variably cloudy solar days, for all seasons. This can be attributed to the fact that hydro has high ramping rates and zero minimum capacity levels. As seen in Chapter 7, even low hydro availability would double penetration levels for variably cloudy days. For the variably cloudy days, penetration levels dropped by up to 1800 MW for January and July. This corresponds to a 36 and 47 percent decrease.

8.3.8 Tie-Line Interchange

This discussion is based on cases 15 and 17 (Tables 8.15 and 8.17). Reducing tie-line capacity by 250 MW decreased PV penetration levels by 200, 400, 600, and 600 MW for January, May, July and October, respectively. This was expected since tie-line would reduce unloadable generation following PV power ouput fluctuations. For sunny, partly sunny and cloudy solar days, there was no clear effect on the PV penetration levels.

8.3.9 Pumped-Storage Hydro Control

Pumped-storage generation control is possible only in the generation mode, as is the case for July. By control, it is meant that pumped-storage hydro plant can ramp down to reduce unloadable generating capacity. Similar to conventional hydro plant, pumped-storage has high ramping rates, thus would absorb severe PV power fluctuations by up to its generating capacity. Case study 18 was performed to test this assumption. Zero hydro availability was assumed so as to show the impact of pumped-storage control alone on the maximum penetration levels. By examining Table 8.18, pumped-storage hydro daily energy was reduced by 85 and 89 MWh for partly sunny and variably cloudy solar days during the month of July. By comparison to case 16, pumped-storage generation control resulted in a 600 and 1400 MW increase under partly sunny and variably cloudy days. As seen early, pumped-storage can reduce penetration levels (generating mode), but at the same time can improve penetration levels if it can be cycled due to PV power fluctuations. This control option is worth investigating.

8.3.10 Concluding Remarks

The impact of the various variables on PV penetration levels has been studied in the previous sections. The following conclusions can be made:

• The PV system available capacity and energy performance have reverse effect on the PV penetration levels. The higher the energy and system availability capacity are, the lower the penetration levels are. The breakeven capital cost was found to increase as the PV energy and availability improve.

• The system ramping capabilities influenced the penetration levels. Examining cases 1 through 4 indicates that as more coal and steam oil units are committed, higher ramping capability exists and more PV can be accepted.

• High hydro generating capacity and availability increase penetration levels, in particular for variably cloudy days.

• High energy costs would indirectly affect penetration levels. In this study high energy costs increased penetration levels.

• Scheduling pumped-storage hydro increases penetration levels when operating in pumping mode and decreases penetration levels when generating. However, allowing pumped-storage to cycle can penetration levels.

• Tie-line interchange increase can improve penetration levels by a factor of two or higher. Such impact is obvious in variably cloudy solar days.

• Penetration levels are quite high in most cases, in particular for sunny and cloudy days. These penetration levels were not accepted all year around. This is due to seasonal variations in load and PV system performance. The PV energy values, critical penetration levels, and breakeven capital costs are discussed next.

8.4 PV Energy Values

Tables 8.5 through 8.18 list PV energy values (PVEV) for maximum penetration levels for the day for the different solar day types. The highest PV energy values were obtained for sunny days. In most cases, the maximum values were obtained for the month of October. The lowest values were, however, obtained for cloudy days due to the low available capacity and energy output of the PV system. In general, the PV energy values vary as a function of load, generation mix, hydro availability and generating capacity, energy costs, and pumped-storage scheduling. Tables 8.19 and 8.20 list lowest maximum penetration levels of the year and the associated PV energy values for Richmond and Raleigh. This level is accepted a year around under various load and weather conditions. These levels are referred to by critical penetration levels.

8.5 Critical Penetration Levels

For Richmond, the critical penetration level fluctuates occured either in January or October, please see Table 8.18. It can be seen that partly sunny weather conditions define the critical penetration level for October. In addition, the critical penetration level occured under partly sunny conditions in July (case 11). Similarly, the season and solar day type at which critical penetration levels existed are more consistent for Raleigh than for Richmond. Again, variably cloudy weather conditions defined the critical penetration levels. Moreover, the critical penetration levels are affected not only by weather conditions, but also by the load shape, peak load and the match between peak load and peak PV power output. In fact, even though January and October have higher peak load than May, the good match between peak load and peak PV power output in May resulted in higher PV penetration levels in May than in the former two months. In July, the peak load size had higher impact on the penetration level than the match did. Combining the effect of weather conditions, load shape size and shape, and PV power performance led to the fact that January and October had the critical penetration level of the year, for both Richmond and Raleigh.

8.6 Breakeven Capital Costs

The breakeven capital analysis, introduced in Section 8.2.4 was performed and discussed next. Figures 8.3 through 8.20 display results of all the case studies. The results are based on an 8 percent interest rate and a 20-year life time. The breakeven capital cost at the critical penetration levels are displayed in Tables 8.19 and 8.20, based on the same economic assumptions.

Results shown in Tables 8.19 and 8.20 reveal that breakeven capital cost increased along with the energy costs. For example, in cases 1 & 7, (Richmond) and in cases 2 & 8 (Raleigh) confirm this observation. Breakeven capital cost also increased as nuclear generating capacity was reduced and coal and steam oil generating capacity was increased. This is true for both Richmond and Raleigh, except in cases 9 and 11 for Richmond, where penetration levels were identical with close breakeven capital cost. The impact of higher steam oil generating capacity on the critical penetration level and breakeven capital cost is well established in Raleigh for both low and high energy costs.

Pumped-storage scheduling has increased both the critical penetration levels and breakeven capital costs for Raleigh (Cases 2 and 14) and for Richmond (Cases 1 and 13). However, it increased the critical penetration level from 2000 to 2800 MW and reduced the breakeven capital cost from \$943 to \$885 per kW, as is the case of case studies 9 and 15. In case study 15, the breakeven capital cost ranged between \$912 and \$871 per kW when penetration level varied from 25 to 3600 MW (Figure 8.17). In case 9, the breakeven capital costs were higher for slightly large penetration levels. It seems that pumped-storage hydro had provided higher critical penetration levels, but resulted in lower breakeven capital costs. Moreover, cycling pumped-storage hydro due to PV fluctuations did not affect the critical penetration level. However, it caused slight improvement in the breakeven capital cost (Cases 16 &18).

Similarly, high hydro availability and high tie-line capacity had provided higher penetration levels, and the same time lowered breakeven capital costs (Cases 15&16, for hydro and cases 15&17, for Tie-line).

8.7 Concluding Remarks

The interactions between PV penetration levels and breakeven capital costs can be summarized in two statements. From the point of view of economists, it is "higher PV penetration level means lower breakeven capital cost". However, from the electric power system operator, it is "higher PV penetration level means more dispatching problems". In fact, higher hydro availability and generating capacity and cycling capacity must always exist to match the PV power output fluctuations. The result is higher PV penetration levels. Such a cycling capacity may include pumped-storage hydro and conventional hydro generation. Tie-line capacity, on the other hand, can be made available on a day-by-day basis. The high penetration levels obtained are somewhat optimistic. First, the capital costs were found low for high penetration levels. Second, fast following generating capacity must exist to make PV acceptable even at high penetration levels. According to this study, the breakeven capital cost for a 10 percent penetration level (1200 MW) was found to be \$968/kW and \$1200/kW for Richmond and Raleigh, respectively, assuming a 20 percent hydro availability, zero pumped-storage hydro capacity, high steam oil generating capacity and high energy costs. This is equivalent to an energy cost of 3.20 and 3.00 ¢/kWh for Richmond and Raleigh.

Table 8.19 Critical PV Levels and Energy Values For Richmond

Case	Month (s)	Solar Day (s)	Critical Penetration Levels (MW)	PVEV (mils/kWh)	Breakeven Capital Cost ($/kW)
1	January	Sunny	1300	36.23	361
3	October	Partly Sunny	2000	37.35	383
5	October	Partly Sunny	1900	13.22	394
7	January, October	Sunny Sunny Partly Sunny	1800	19.99 37.12 25.19	796
9	October	Partly Sunny	2000	42.19	943
11	October	Partly Sunny	2000	31.15	942
13	July	Partly Sunny	2400	7.24	377
15	October	Partly Sunny	2800	29.93	885
16	October	Partly Sunny	1800	34.11	983
17	October	Partly Sunny	2400	30.12	892
18	October	Partly Sunny	1800	34.11	891

Table 8.20 Critical PV Levels and Energy Values For Raleigh

Case	Month (s)	Solar Day (s)	Critical Penetration Levels (MW)	PVEV (mils/kWh)	Breakeven Capital Cost ($/kW)
2	January	Sunny Intermittent	700 700	21.04 11.38	470
4	January	Intermittent	1400	11.69	488
6	January	Intermittent	1200	11.54	501
8	January	Sunny Intermittent	1000 1000	38.88 24.40	1095
10	October	Partly Sunny	2000	31.46	1106
12	January	Intermittent	1400	27.25	1190
14	January	Intermittent	2000	11.85	481

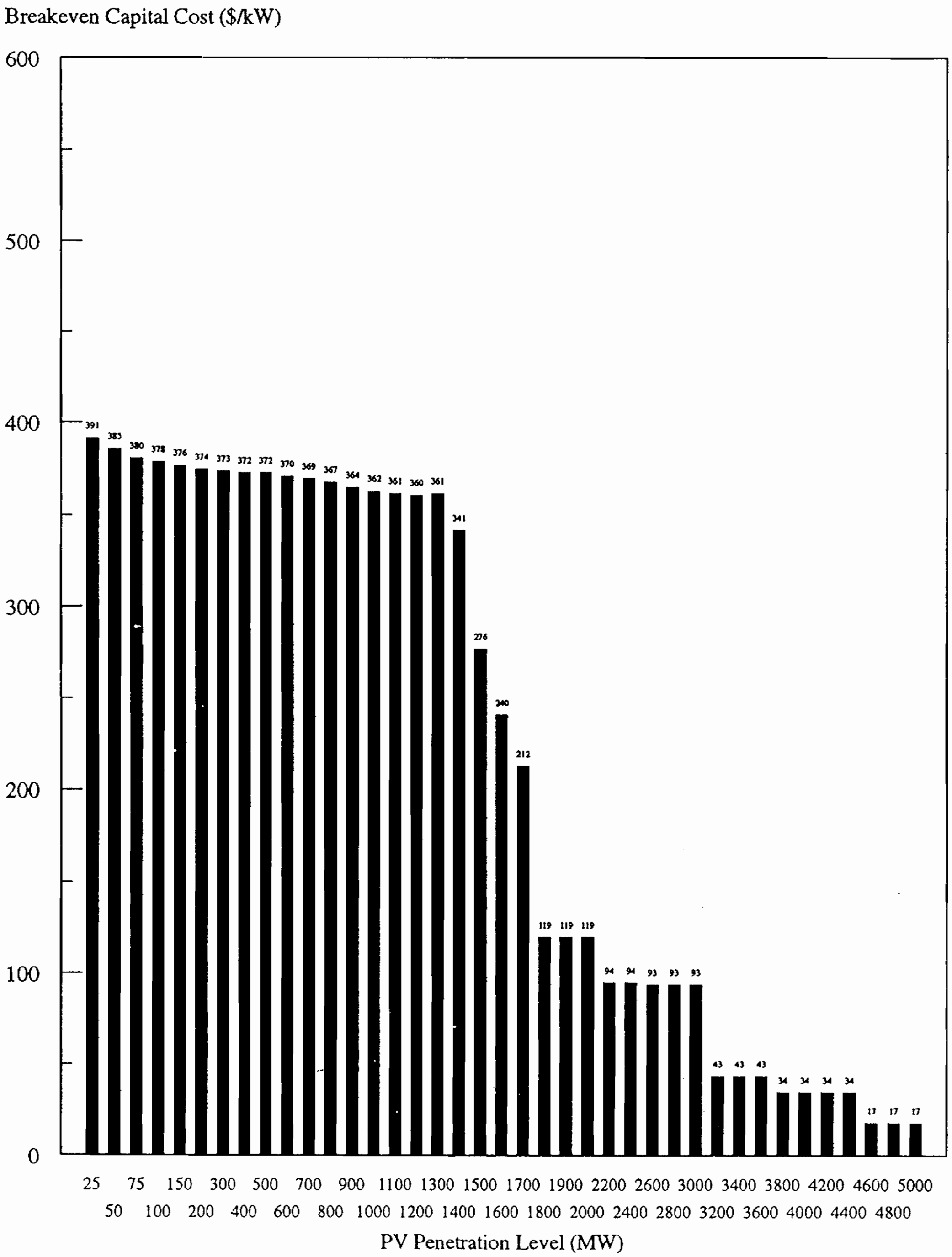


Figure 8.3 Breakeven Capital Cost for Richmond: Case 1

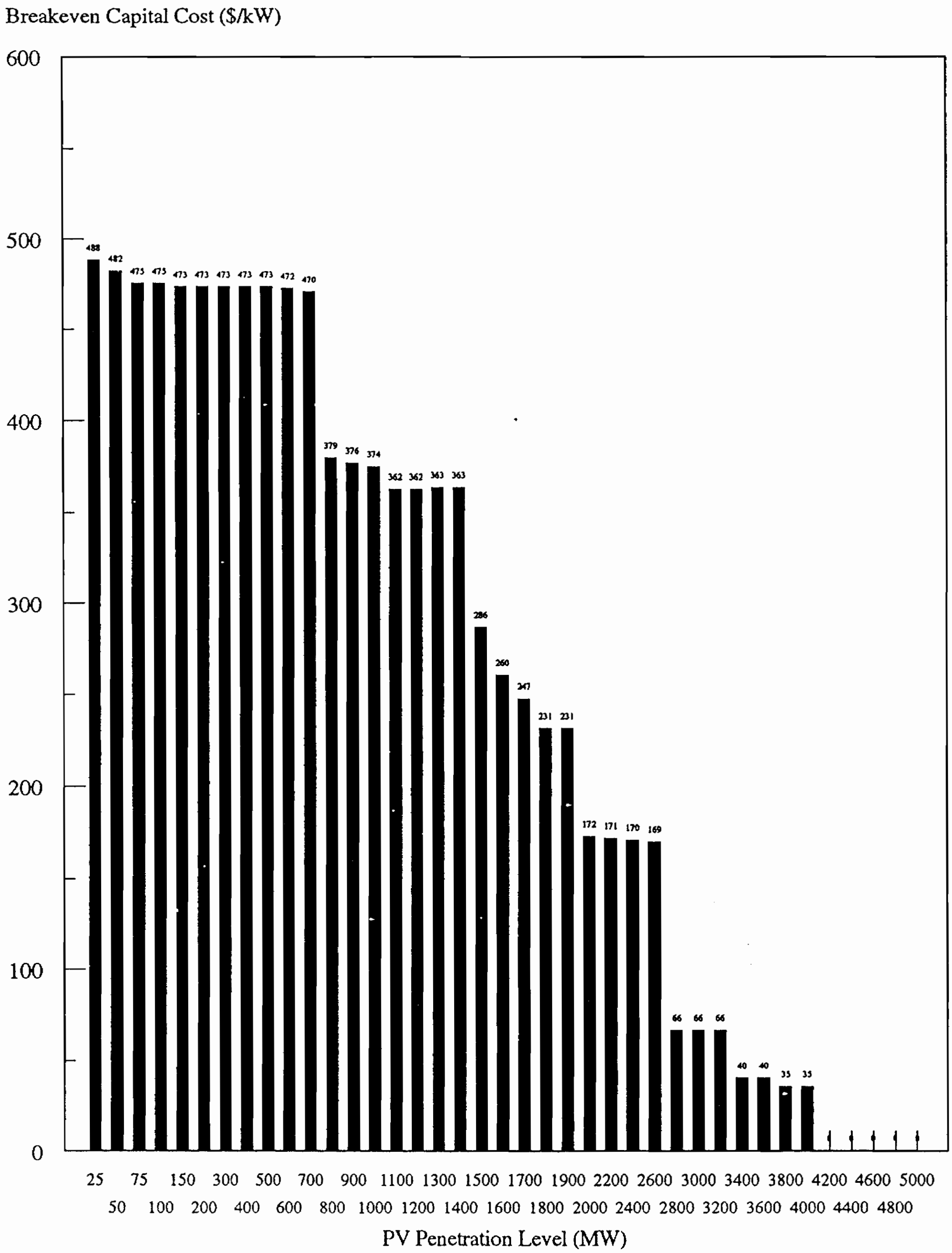


Figure 8.4 Breakeven Capital Cost for Case 2

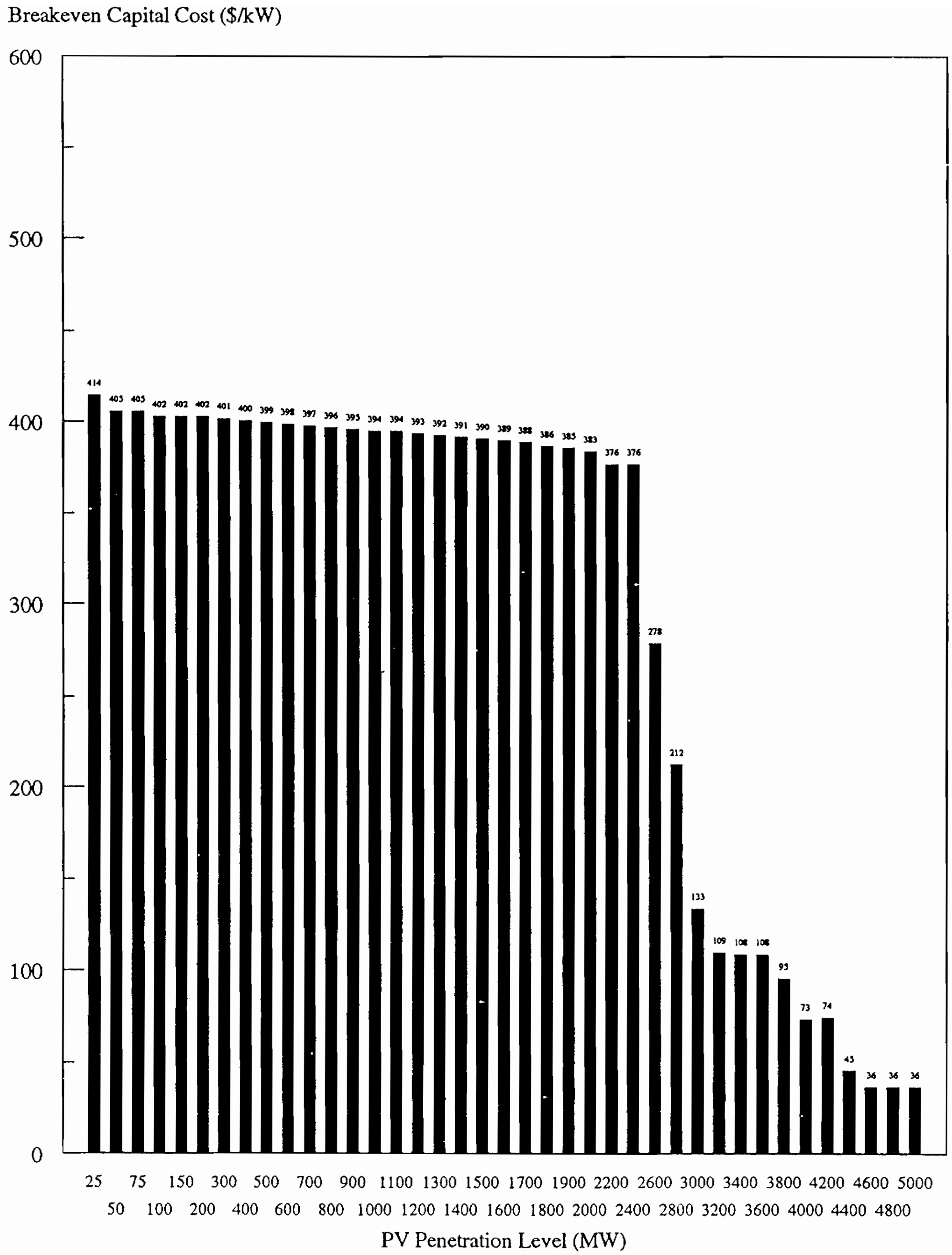


Figure 8.5 Breakeven Capital Cost for Case 3

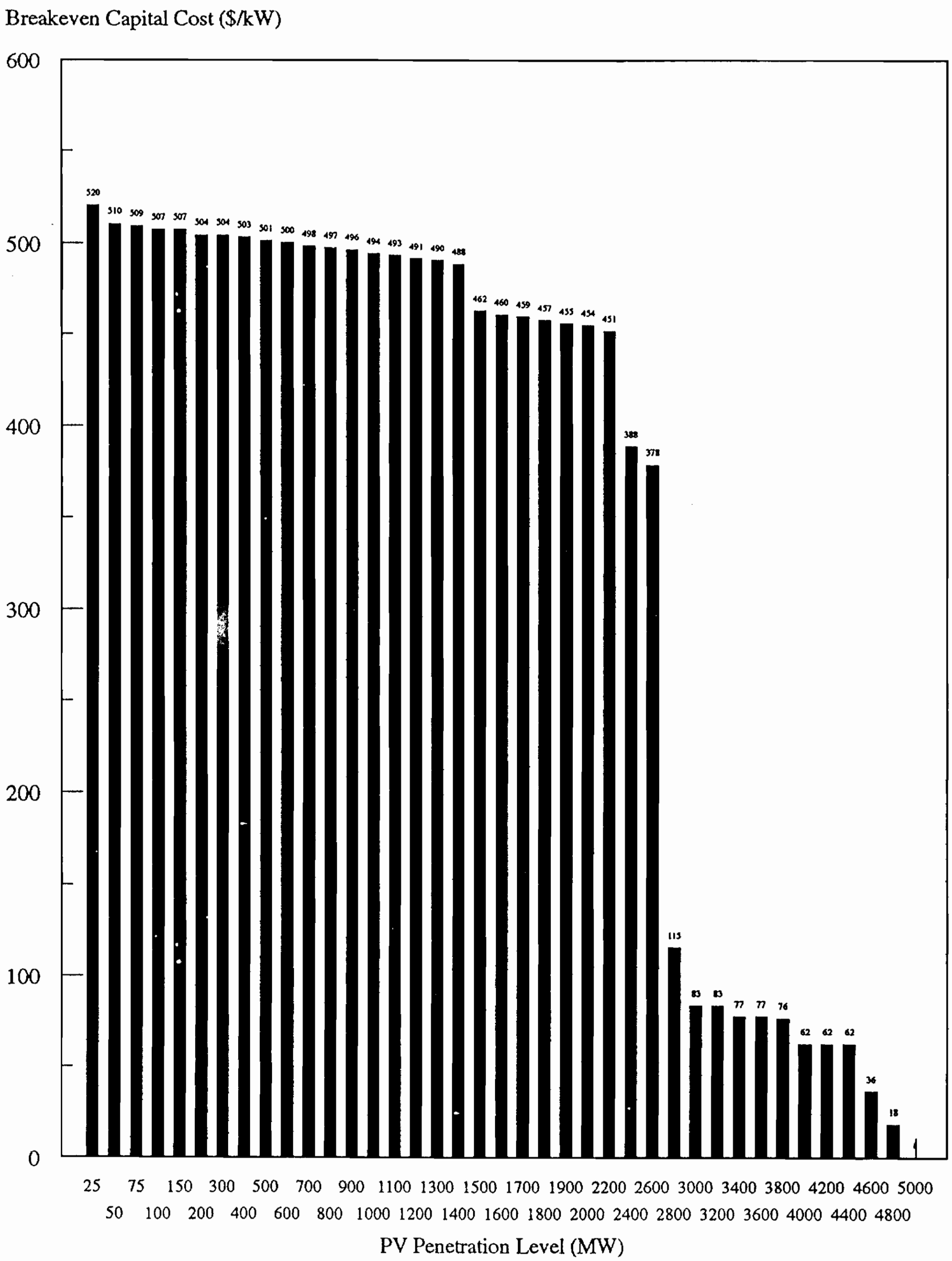


Figure 8.6 Breakeven Capital Cost for Case 4

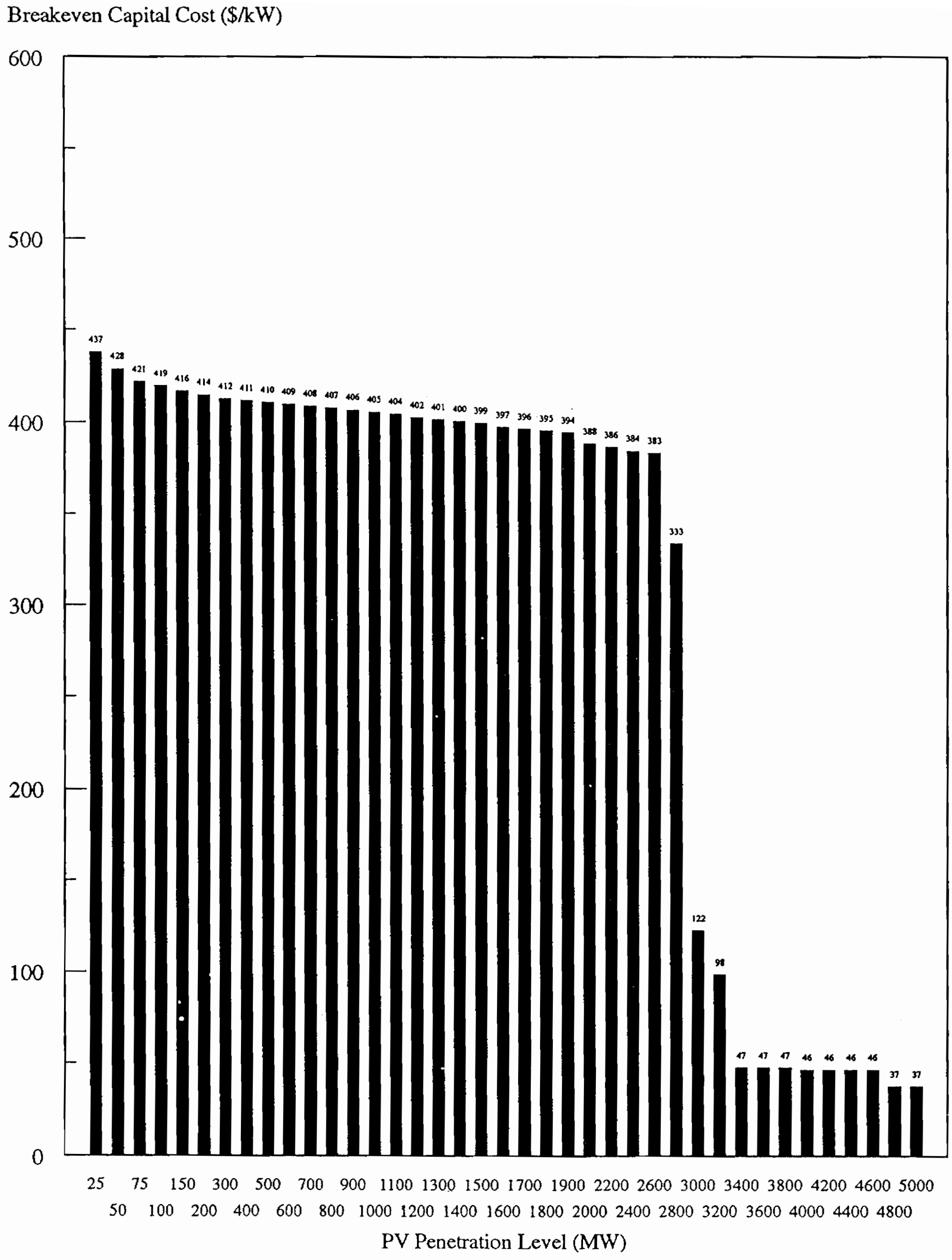


Figure 8.7 Breakeven Capital Cost for Case 5

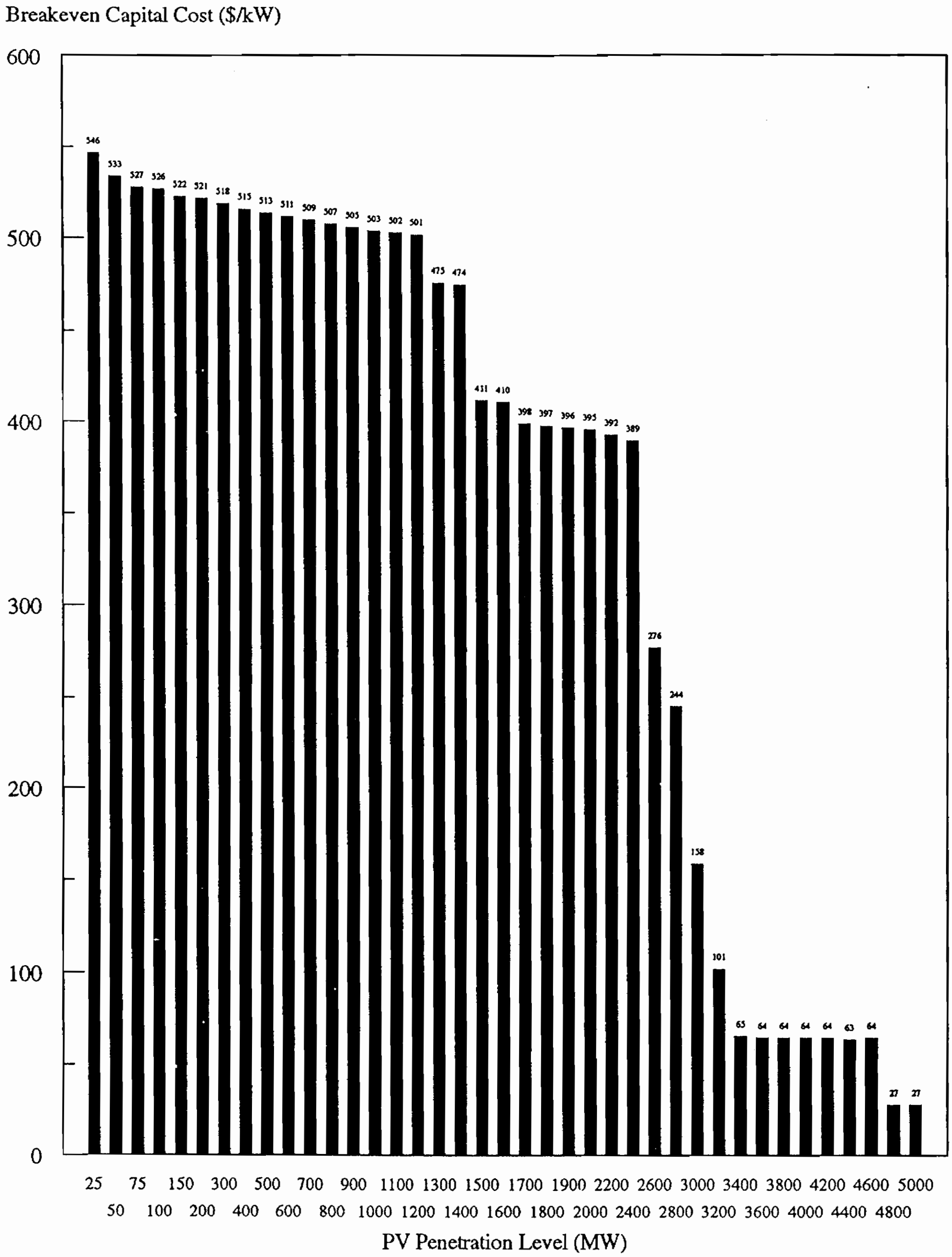


Figure 8.8 Breakeven Capital Cost for Case 6

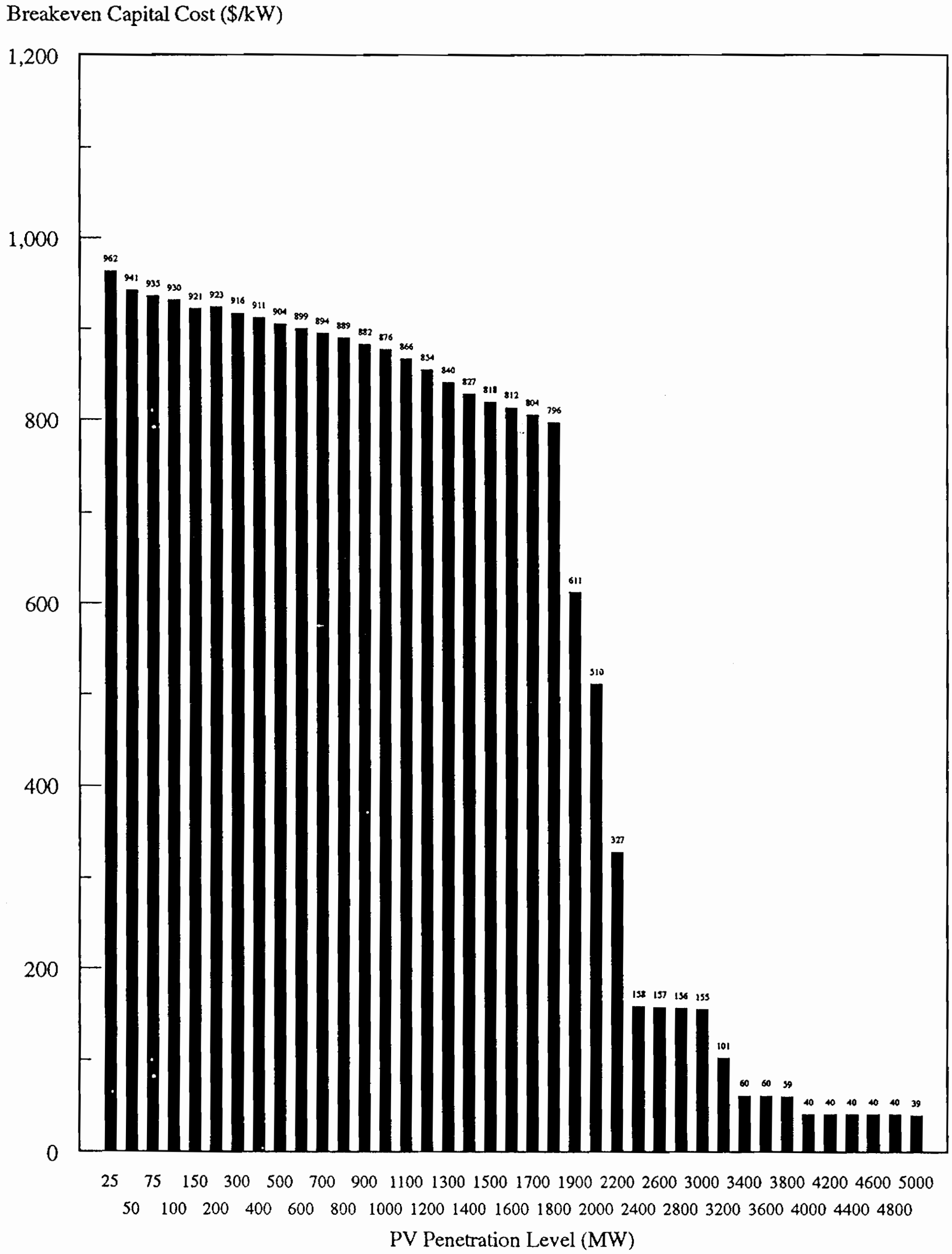


Figure 8.9 Breakeven Capital Cost for Case 7

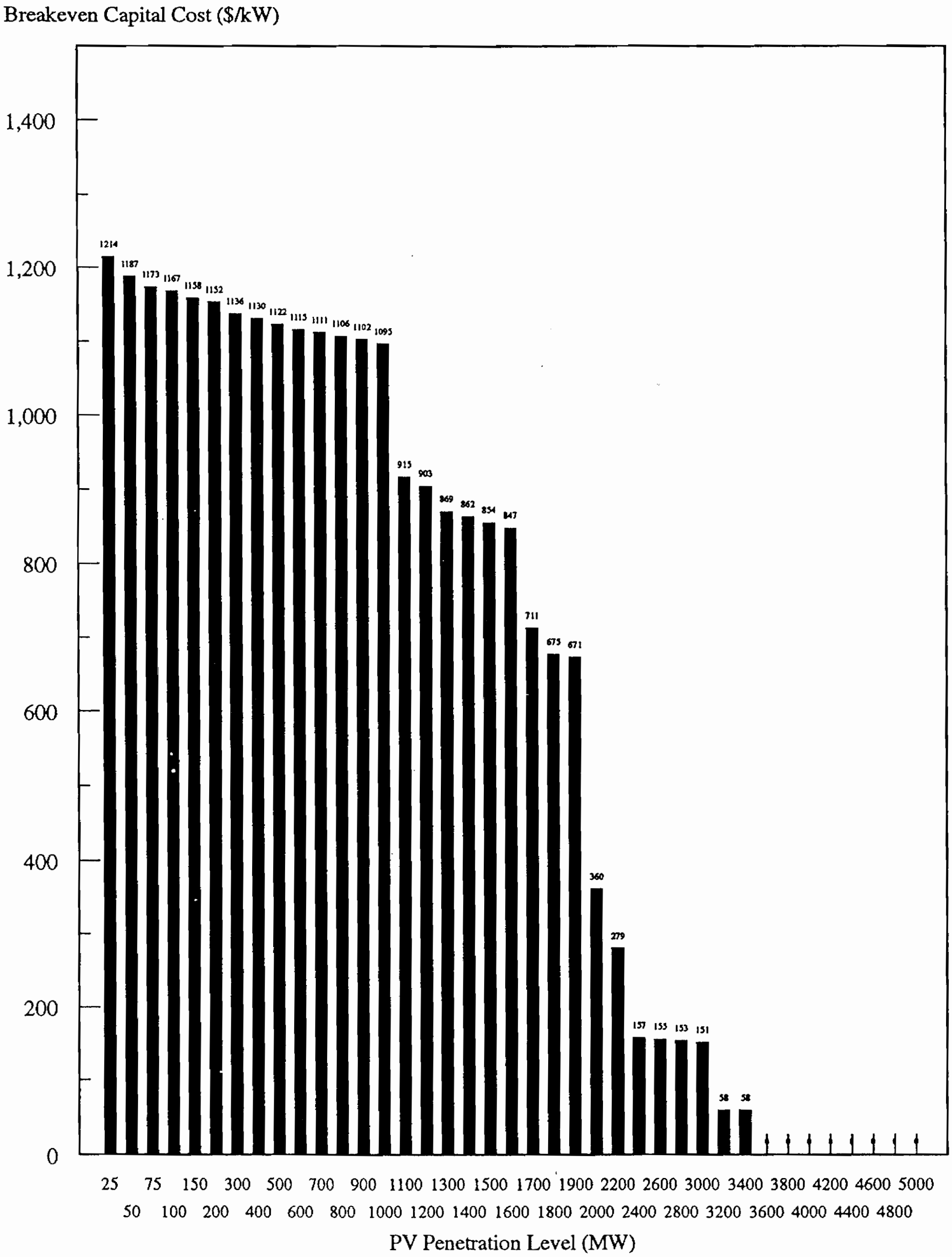


Figure 8.10 Breakeven Capital Cost for Case 8

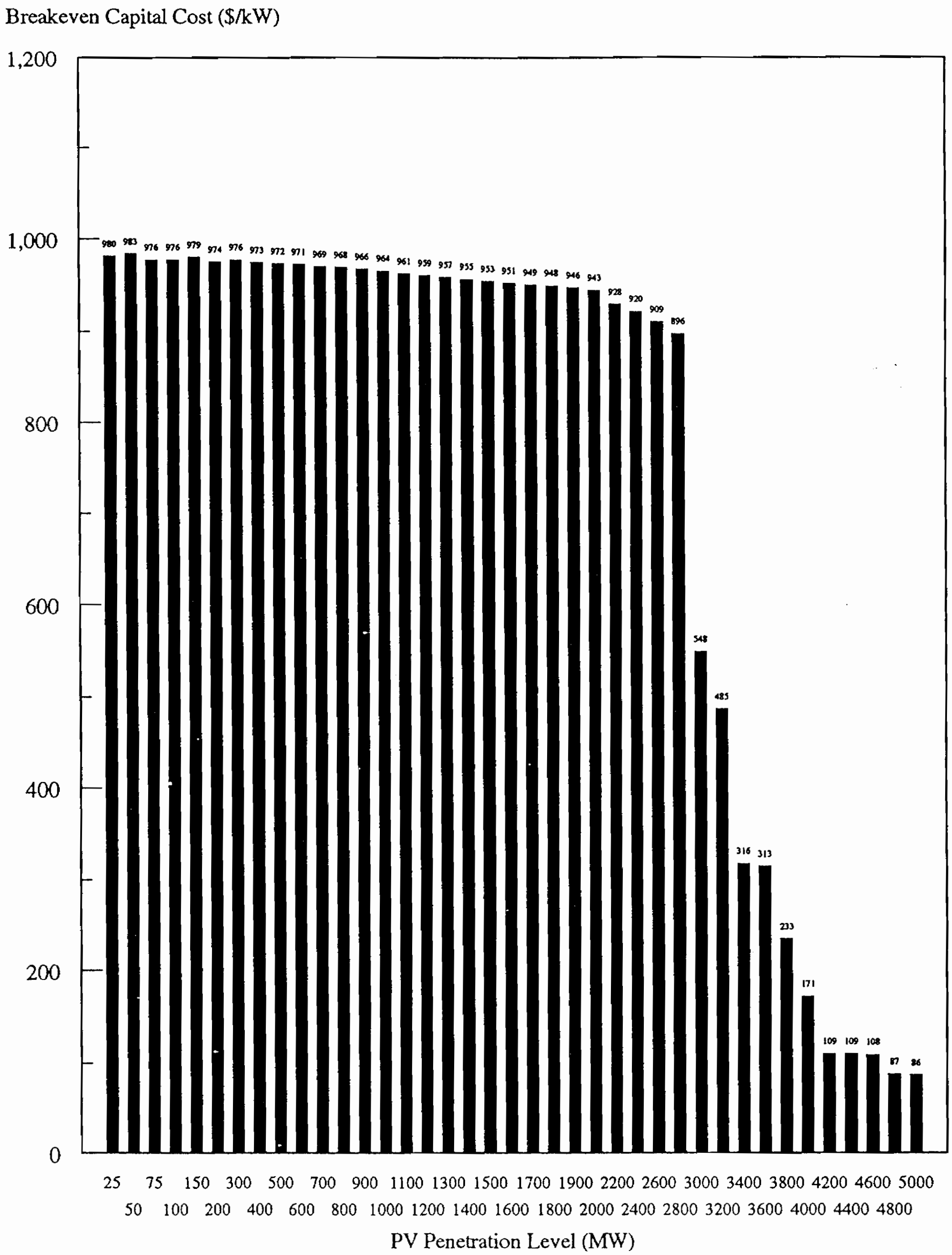


Figure 8.11 Breakeven Capital Cost for Case 9

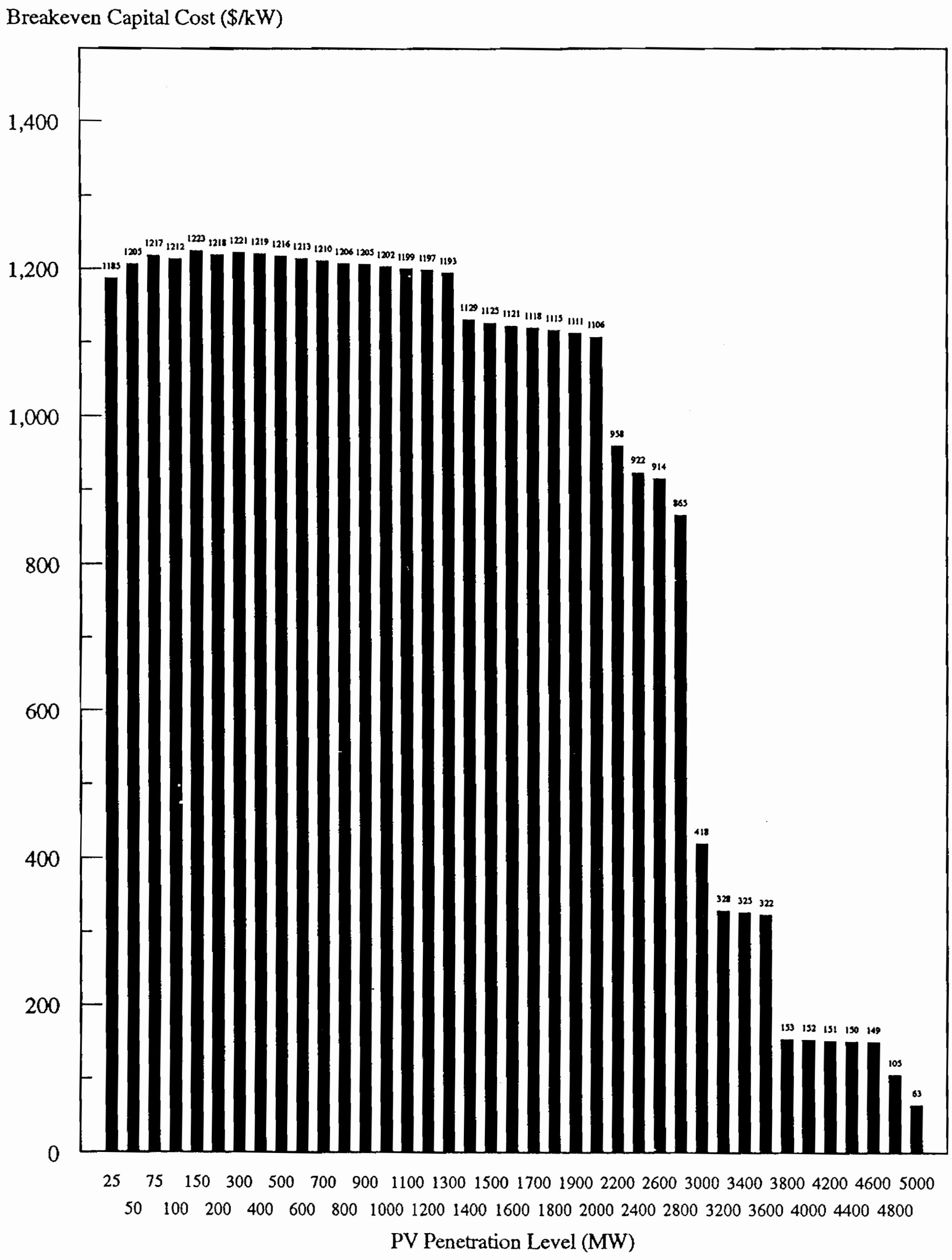


Figure 8.12 Breakeven Capital Cost for Case 10

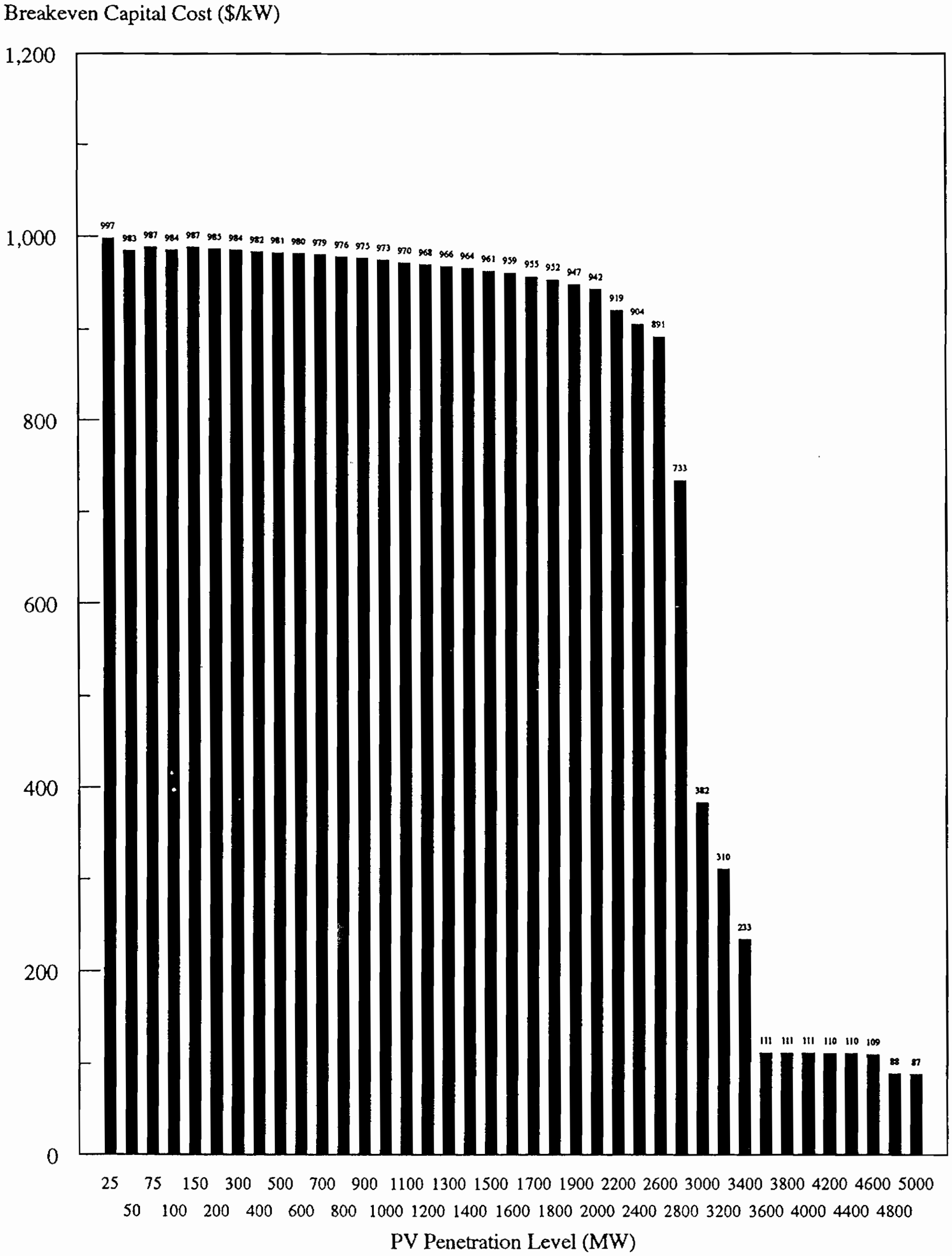


Figure 8.13 Breakeven Capital Cost for Case 11

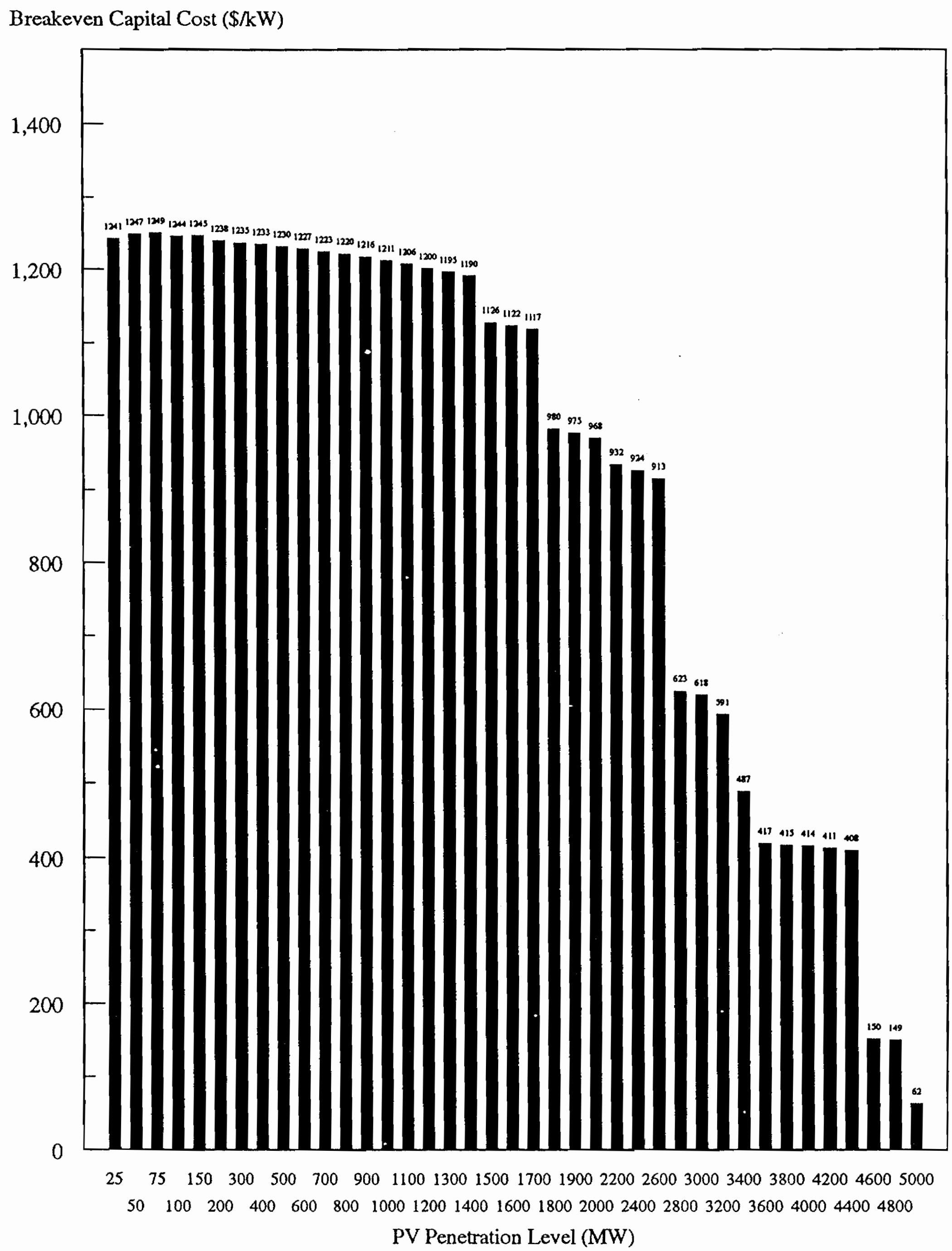


Figure 8.14 Breakeven Capital Cost for Case 12

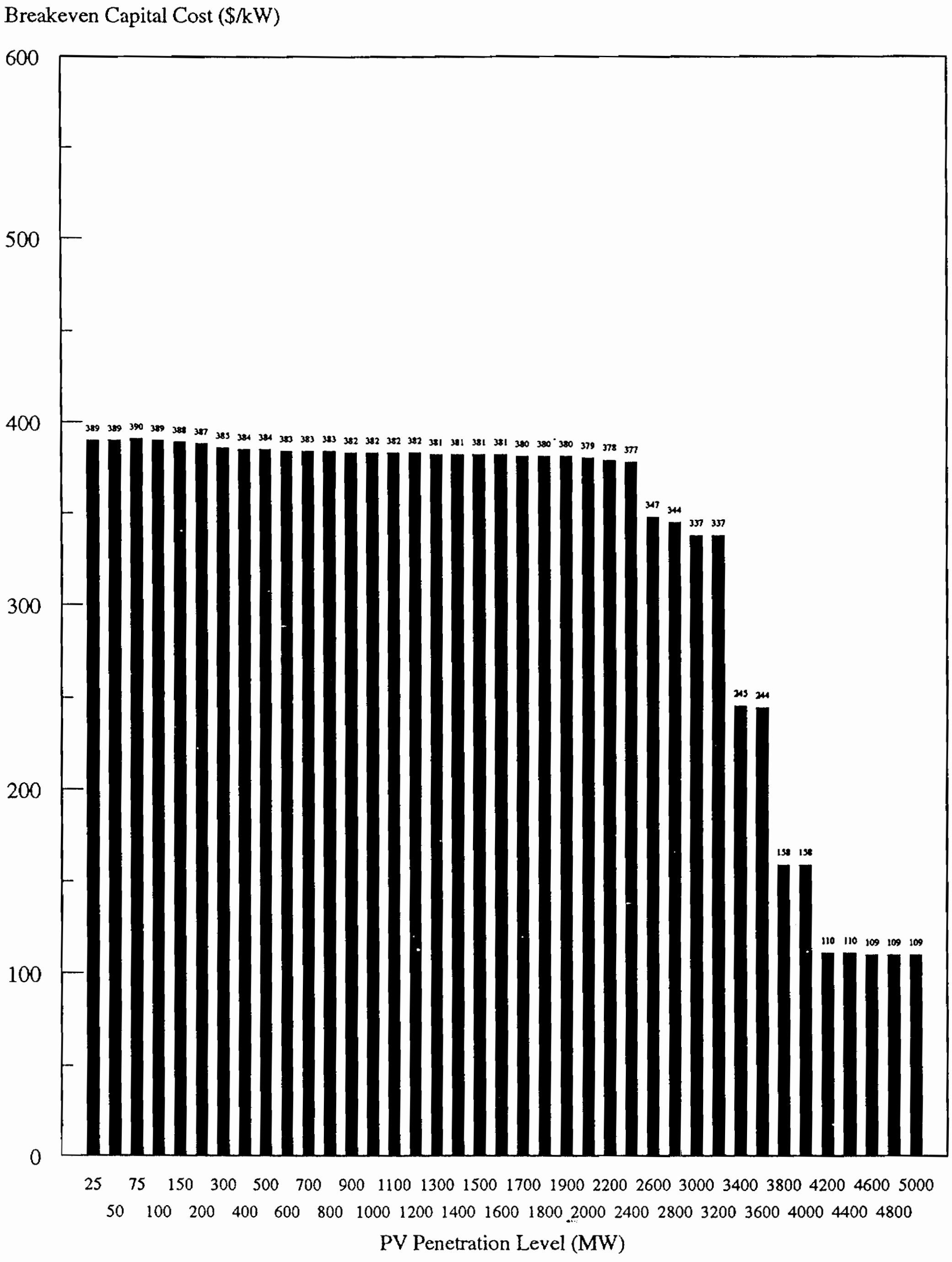


Figure 8.15 Breakeven Capital Cost for Case 13

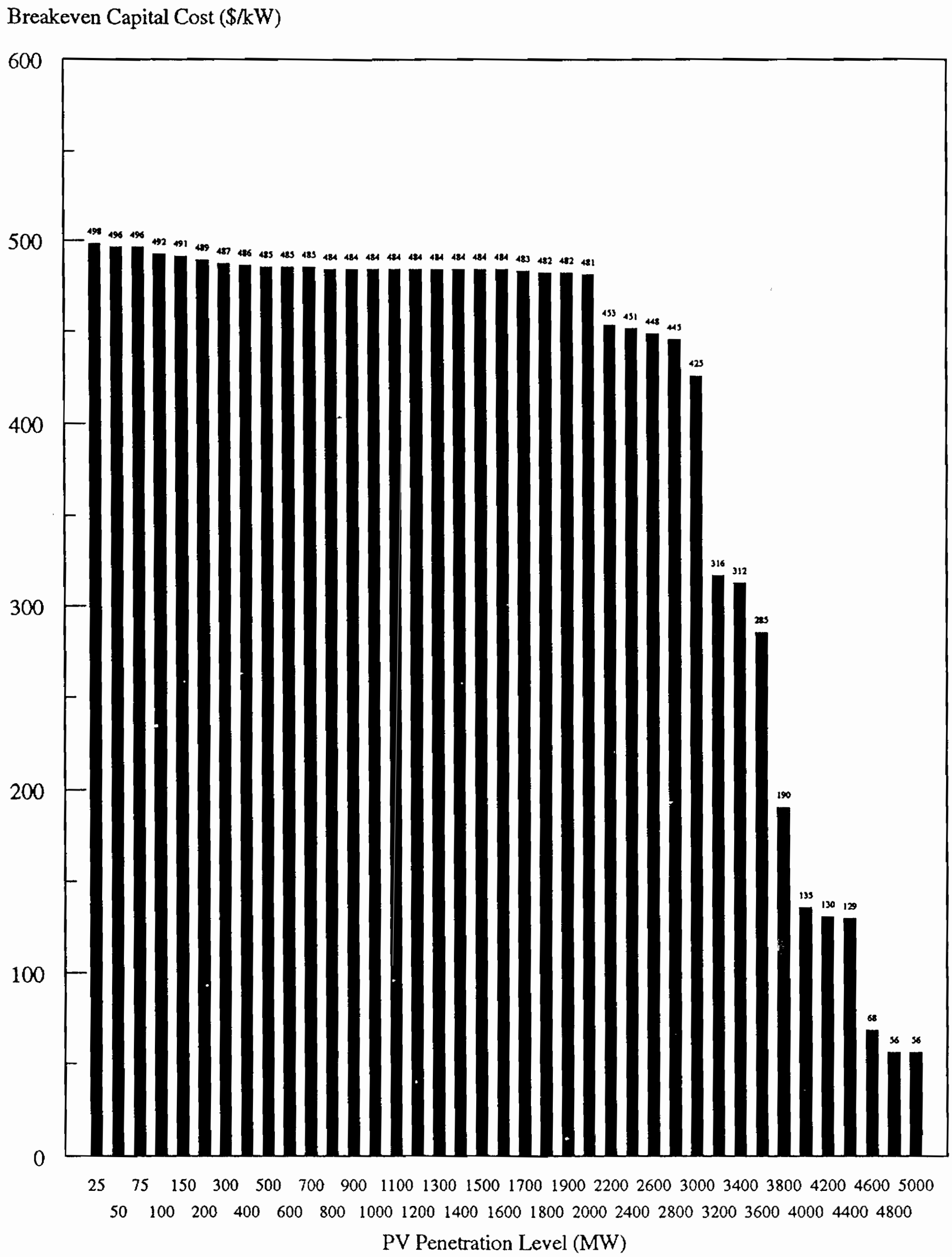


Figure 8.16 Breakeven Capital Cost for Case 14

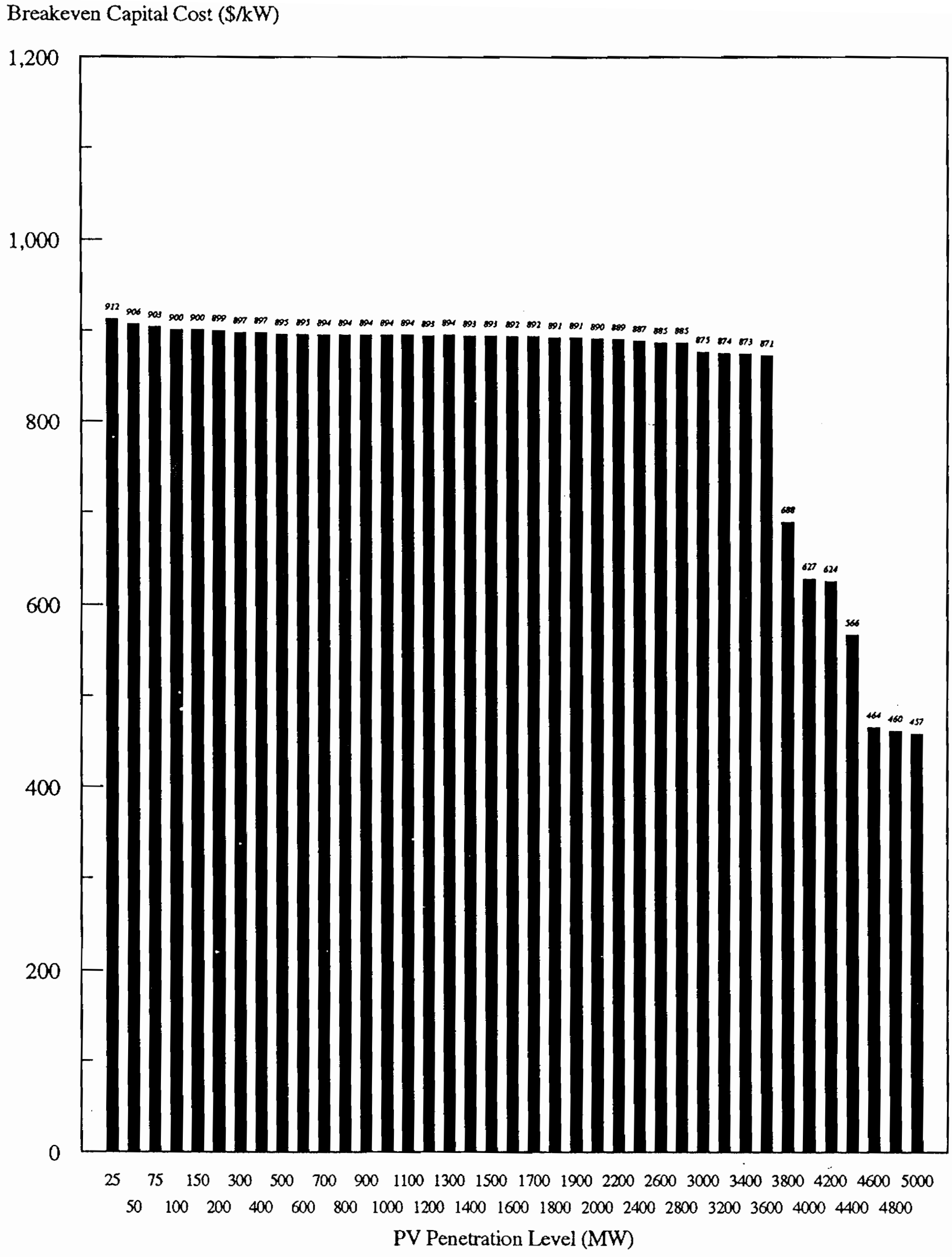


Figure 8.17 Breakeven Capital Cost for Case 15

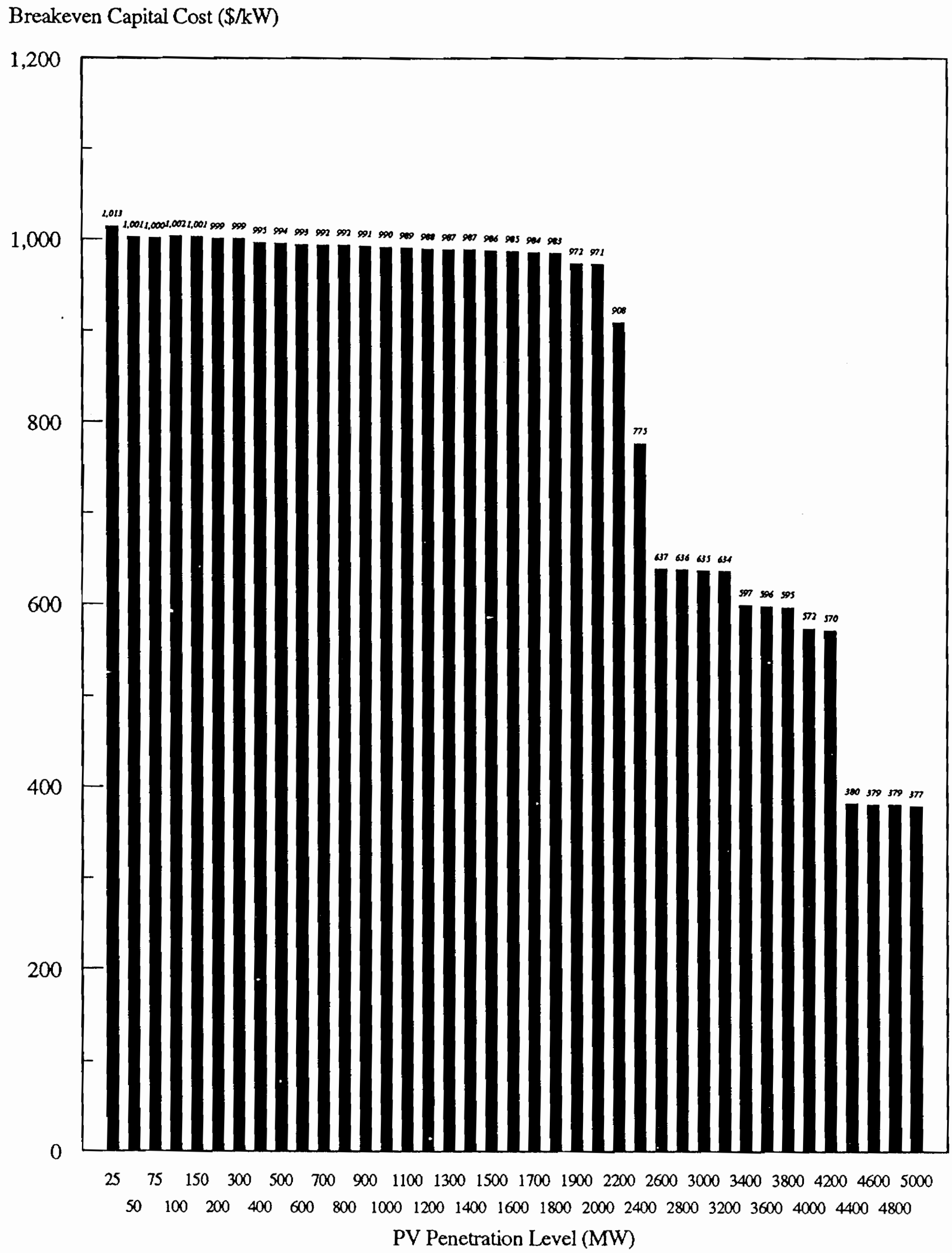


Figure 9.18 Breakeven Capital Cost for Case 16

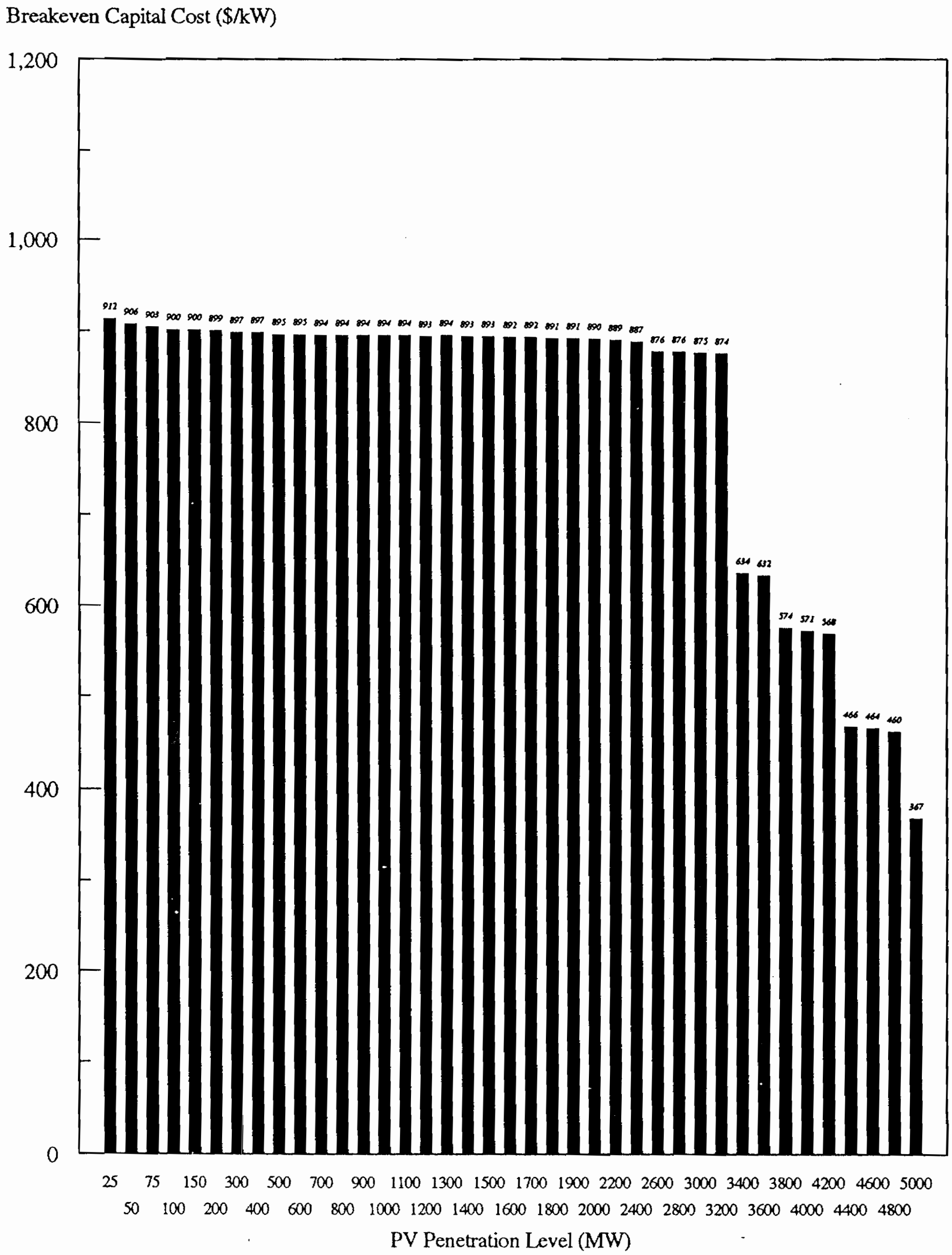


Figure 8.19 Breakeven Capital Cost for Case 17

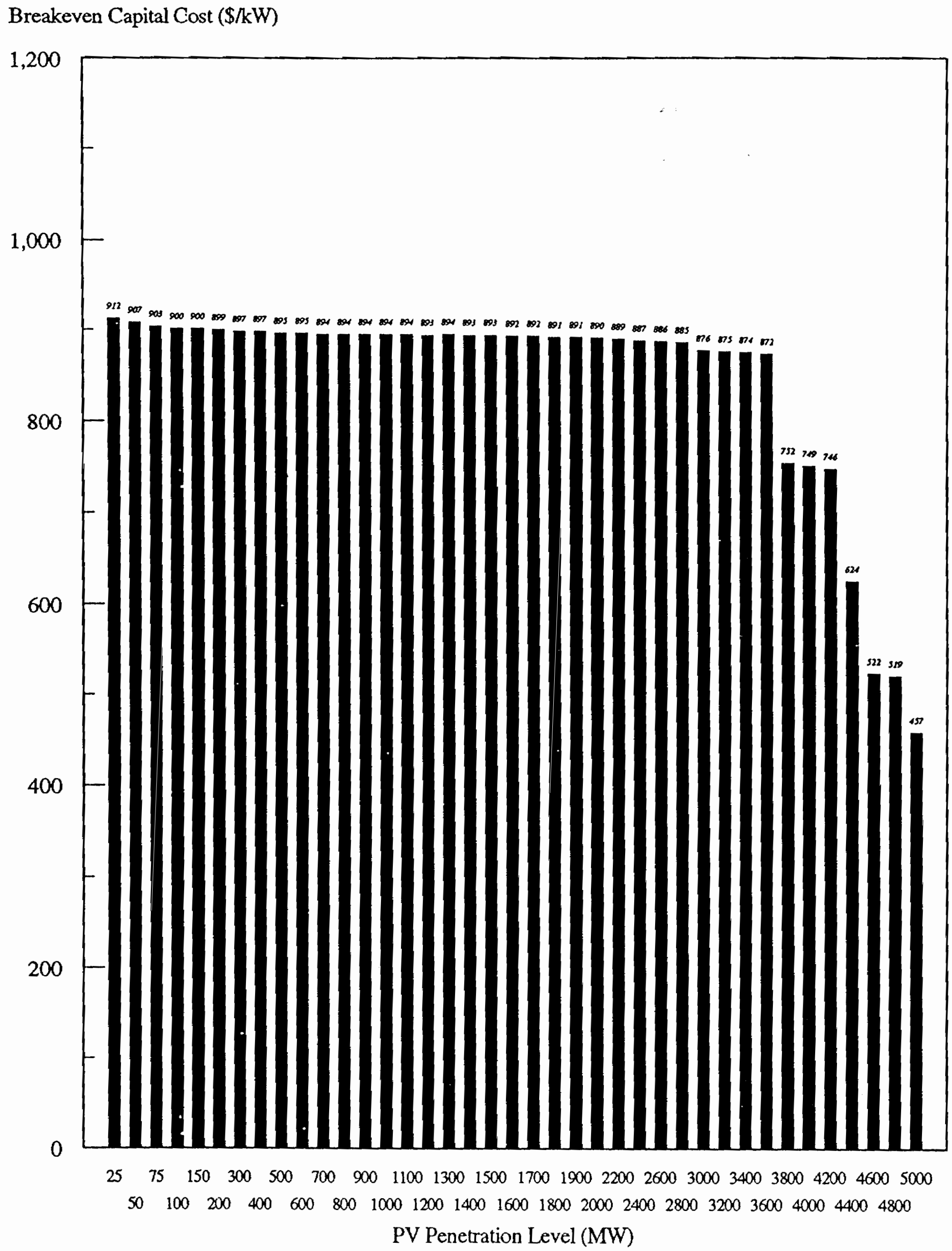


Figure 8.20 Breakeven Capital Cost for Case 18

CHAPTER 9.

CONCLUSIONS AND RECOMMENDATIONS

In this study, various parameters that would enhance the operational and economical value of incorporating large-scale PV systems have been investigated. Issues such as the impact of generation mix and fuel costs, the ranges of per unit PV energy values, and the breakeven capital costs for large-scale penetration were addressed. It was found that the energy costs ranged from 1.4 ¢/kWh to 15.3 ¢/kWh for a $2000/kW capital cost for 25 and 10.55% system annual capacity factors. On the other hand, the breakeven capital cost was found to range from $361 to $943 per kW for Richmond, Virginia and from $470 to $1193 per kW for Raleigh, North Carolina, asuming a 20 percent hydro availability and zero pumped-storage hydro generation.

Generation mix, fuel costs, PV resource availability, system load, and prevailing weather conditions influenced the economic value of PV systems, i.e., the per unit energy value and breakeven capital cost. Similarly, hydro dispatching, fast ramping rates and tie-line interchange improved the PV penetration and dispatching, thus enhanced the breakeven capital cost.

On the other hand with pumped-storage hydro, maximum allowable penetration levels increased significantly. However, the associated breakeven capital cost either improved slightly or decreased. For example, for low energy costs, the penetration level and breakeven costs increased from 1300 MW to 2400 MW and from \$361 to \$377/kW, for Richmond. For the 1300 MW penetration level, breakeven capital cost improved by \$20 /kW. On the other hand, at high energy costs and high nuclear generating capacity, the PV penetration level increased from 2000 to 2800 MW, while the breakeven capital cost decreased from \$943/kW to \$885/kW, for Richmond. However, considering the same penetration level (2000 MW), the breakeven capital cost was only \$890/kW.

In this study, the breakeven capital cost was found to be high for low penetration levels and low for high penetration levels. This is expected because as the PV system assumes low capacity, it would be entirely dispatchable throughout the year. However, as the PV penetration level increases, the PV system may not be entirely dispatchable throughout the year. This will cause a significant drop in the annual savings per kW.

In this study, the breakeven capital cost depends on a zero energy wastage and the occurrence probability of each solar day type. Therefore, the breakeven cost would improve if both good prevailing weather conditions and steady PV performance would exit. This requires careful plant siting, proper resources assessment, and efficient solar cells. Knowing the available resources and prevailing weather conditions, the proposed technique would provide the right assessement tool to maximize PV system usage.

According to this study, at a 10 percent penetration level (1200 MW) and high energy costs, the breakeven capital cost would be \$968/kW and \$1200/kW for Richmond and Raleigh, respectively, assuming a 20 percent hydro availability, zero pumped-storage hydro capacity and high steam oil generating capacity. This corresponds to an energy cost of 3.20 and 3.00 ¢/kWh for Richmond and Raleigh.

The interactions between PV penetration levels and breakeven capital can be summarized in two statements. From the point of view of the economists, it is "higher PV penetration level means lower breakeven capital cost". However, from the electric power system operator point of view, it is "higher PV penetration level means more dispatching problems". In fact, higher hydro availability and generating capacity and fast ramping generating capacity must always exist to support the PV system. These conditions may not be true all year around, as is the case for pumped-storage hydro and conventional hydro systems power plants. Tie-line capacity, on the other hand can vary from one day to another and can be subject to prior agreements. The high penetration levels obtained are only but optimistic. In fact, the breakeven capital costs are low. Moreover, fasting generation must exist to support the PV system at high penetration levels.

In this study, the operational and economical values of PV system are specific to the utility in terms of its load characteristics, generation mix, resource availability, and prevailing weather conditions. Results presented here however are specific to the location and utility generation mix considered. The technique presented here is generic and can be used to model a diverse set of conditions. In order to get generalized results which are widely applicable, studies have to be conducted using solar and PV performance data from different locations and generation mix from various utilities. In addition, studies have to be conducted which will take into account the full cost of generating electricity using conventional means. Thus the true impact of environmental externalities can be reflected on the PV breakeven costs.

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APPENDIX A

PV ENERGY COST ANALYSIS

To study the cost of energy produced by the PV system, the following energy cost analysis was conducted using Richmond, VA Tech and Raleigh PV solar facilities. Their costs are compared against the energy cost for the distributed PV system. The cost of energy supplied by the three facilities was determined using the PV output data for 1990 for Richmond and VA Tech, and 1986-87 for Raleigh. The nominal ac output ratings for these PV plants are 60 kW, 2.5 kW, and 4.0 kW respectively. For the purpose of comparison, rated outputs from all these sites are scaled up to 1000 MW (ac). The distributed PV system consists of the three sites, each rated at 333 MW. Table A.1 lists monthly and annual energy produced by the three facilities as well as by the distributed PV system. The annual capacity factors are also included. The economic assumptions listed below used in this study are listed in Table A.2. Table A.3 displays various energy costs (¢/kWh) using different economic assumptions, of capacity factors and, PV capital costs. Here the capacity factor is given by:

$$\textbf{Capacity Factor (\%)} = 100 \times \frac{\textbf{Annual Energy Produced (MWh)}}{\textbf{PV Installed Capacity (MW)} * \textbf{8760 (hour)}}$$

Table A.1 Monthly and Annual Energy (MWh)

Month	Richmond	VA Tech	Raleigh	Distributed
January	52 885	71 005	97 782	73 891
February	36 678	86 349	78 068	67 032
March	90 130	105 000	96 907	97 346
April	33 793	110 815	64 863*	69 824
May	106 650	101 772	64 863	91 095
June	137 219	118 733	145 699	133 884
July	81 985	107 906	150 441	113 444
August	65 738	92 961	96 838	85 179
September	75 355	85 195	113 581	91 377
October	86 659	74 491	104 683	88 611
November	104 594	110 662	30 509	81 922
December	52 570	66 505	100 667	73 247
Annual Energy	924 256	1 131 394	1 144 901	1 066 850
Cap. Fac. (%)	10.55	12.91	13.06	12.17

* No data were available for April, May data were used instead.

Table A.2 Economic Assumptions

PV Operating Life	20 years
Availability	90 %
Amount of Loan	95% of the installation cost
Loan Term	20 years
Loan Interest Rate	8 %
O&M Costs [36]	0.5 ¢/kWh
O&M Escalation Rate	4.9%
Depreciation	20 years
Salvage Value	$ 20.00/kW
Maximum Capacity Factor	25 %

Table A.3 Energy Cost (¢/kWh)

Capital Cost ($/kW)		2000	3000	4000	5000	6000	2421*
Capacity Factor (%)	Annual Energy (GWh)	Energy Cost (¢/kWh)					
10.55	924 (Richmond)	15.3	28.3	40.8	53.2	65.7	21.1
12.17	1066 (Distributed)	12.5	23.3	34.1	44.9	55.8	17.0
12.91	1131 (VA Tech)	11.2	21.4	31.6	41.8	52.0	15.5
13.06	1144 (Raleigh)	11.0	21.1	31.2	41.2	51.3	15.3
15.00	1314	8.4	17.2	26.0	34.7	43.5	12.1
20.00	1752	4.0	10.6	17.2	23.8	30.4	6.8
25.00	2190	1.4	6.7	11.9	17.2	22.5	3.6

VITA

Mounir Bouzguenda was born on October 2nd, 1960 in Sfax, Tunisia. After graduation from high school 'Lycée de Garçon, Hédi Chaker', Sfax, Tunisia in 1981. In January, 1982, he entered the Pennsylvania State University, University Park as an electrical engineering major. He received a Bachelor of Science degree in Electrical Engineering and a minor in Mathematics in 1985. In September 1985, he entered Virginia Tech to work toward a Master of Science degree in Electrical Engineering. In December 1987 he obtained his Master of Science degree, specializing in the power system area.

Mounir Bouzguenda held a research assistant position at the Alternate Energy Systems Laboratory, Virginia Tech since 1985. He also worked as a teaching assistant in several courses in the undergraduate and graduate levels.

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