NREL/TP-462-5337 · UC Category: 1371 · DE94006947

The State of Energy Storage in Electric Utility Systems and Its Effect on Renewable Energy Resources

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A national laboratory of the
U.S. Department of Energy
Managed by Midwest Research Institute
under Contract No. DE-AC36-83CH10093

Prepared under Task Nos. AS815440 and AS819205

August 1994

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Preface

It is believed that storage is a facilitating technology for the integration of intermittent renewable energy resources into a utility's system. A combination of storage and intermittent renewable energy resources can mitigate the intermittence of output. Consequently, the state of the art of storage technologies and their development are of consuming interest to the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL). This study of storage technology was conducted by the Analytic Studies Division of NREL for the Office of Utility Technologies (OUT) of DOE.

This report summarizes the state of the art of different storage technologies and the different modes of storage dispatch to achieve disparate benefits in a utility's network. In addition, an attempt has been made to examine the effect of the infusion of intermittent renewable energy resources on storage benefits in one mode of storage dispatch.

Approved for the
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Executive Summary

Renewable energy technologies are attractive because of their benign effect on the environment. Some renewable technologies, such as hydro power and biomass, have been used in the past. Of recent interest is the possibility of large-scale integration into utility networks of technologies, such as wind and photovoltaics, for power generation. A shortcoming of these latter technologies is their intermittence arising from the intermittence of the resource (wind velocity or insolation). Therefore, it is natural to expect that by using some form of energy storage as a buffer, the output from a combination of these resources can be more or less uniform.

An intent of this report is to describe the state of the art of storage technologies. Such a description includes the benefits that can be derived from dispatching storage in different operating modes. Such a narrative leads to the inevitable question regarding how the penetration of intermittent renewable technologies (IRETs) into a utility's network affects the benefits from storage dispatch. Therefore, the secondary objective of this report is to examine the effect of IRET penetration on storage benefits.

To these ends, various ways of operating a storage installation to obtain disparate benefits in a utility's system are the first subject of discussion. Historically, of all the modes of storage dispatch, load leveling has been the most widespread application. The marginal cost of electricity production increases with the demand of the load on the system. Therefore, in order to curtail higher cost generation during times of high loads, energy from a storage device is discharged to augment generation. Energy is put into the device (or stored) during times of lower costs (loads). Consequently, energy is stored at a lower cost and is used to displace higher cost generation. Because of this process, the system load is increased during charging and reduced during discharging of storage. As a result, the difference between the peak load and the lowest load on the system is minimized.

Of late, operation of storage to obtain dynamic benefits is contemplated. Dynamic benefits include load frequency control, spinning reserve provision, transient stability improvement, and load following capability. An example of such an operation is that of Puerto Rico Electric and Power Authority, which is in the process of installing batteries to act as spinning reserve and to aid in the control of frequency. The details of this and other dynamic benefits comprise Section 2 of this report.

A discussion of different storage technologies and their costs follows in Section 3. The discussion contains a brief description of pumped storage, battery energy storage, compressed air energy storage, superconducting magnetic energy storage, thermal energy storage, and flywheel energy storage.

The motivation to install storage with IRET generation can arise from two considerations. The first is reliability related. This means that the storage acts as a backup to the IRET in the event of the absence of the renewable resource (e.g., absence of insolation or wind). The combination of IRETs and storage provides a reliable supply. However, the addition of storage for reliability purposes increases the cost of such installations. Consequently, reliability-related storage is attractive only if the accruing benefits exceed the cost of installation.

The second motivation for the installation of storage is that it could enhance the value of energy. The output of the IRET, if not naturally occurring at the time of high system marginal cost, can be stored and depleted during high cost periods. Contrary to such intuitive first thought, it is shown that the operation of the storage should not be guided by the output of the IRET. Rather, its operation, guided by the system marginal costs, results in additional benefits. Consequently, in planning studies to quantify benefits, storage should be considered as an entity belonging to the system and not as a component of IRETs.

To maximize benefits, storage has to be sized (kilowatt and kilowatt-hour capacity) properly. Understandably, the optimum kilowatt and kilowatt-hour capacity of storage depends on the mode of dispatch and system parameters. Nevertheless, it is evident that the optimum size for a system without any IRET generation could be different from the size of storage in the same system with IRET penetration. In a similar vein, if optimal storage is installed in a system, later infusions of IRETs into the system could alter the benefits. In that sense, therefore, there is a relation between storage and IRETs.

The second consideration of this study is the relationship between IRETs and storage. The relation between them depends on the dispatch mode of storage. The scope of our study did not allow the examination of all possible modes of operation. Consequently, one mode of operation—that of load leveling—was selected for further examination.

Appendix 2 shows the results of a study involving a hypothetical system. Storage contributes capacity at the time of system peak. Hence, it obtains capacity credit. However, it is shown that because the infusion of IRET energy tends to reduce system marginal cost, the benefits due to load leveling (value of energy) would be reduced. Similarly, if storage already exists in a system that is being operated in the load leveling mode (e.g., pumped storage plants), infusion of IRETs would diminish benefits, and in some instances, storage requirements.

This situation is not unique to IRETs and can arise from demand-side management and other initiatives. Under such circumstances, a reorientation of the dispatch of storage into other modes to maximize benefits would be necessary.

As a cautionary note, it is necessary to stress that these findings apply only to the dispatch of storage in the load leveling mode. Other modes of dispatch to obtain disparate benefits have to be examined before any general conclusions can be made. For example, if the benefits of dispatch in the load leveling mode diminish because of the infusion of IRETs, one might consider dispatching storage existing in modes other than that of load leveling to increase benefits. A portion of the storage can be used to serve as a reliability backup to the IRET. The benefits of such alternative deployment of storage are system specific. Only by conducting system-specific studies will a fuller understanding of the relationship between storage and IRETs be obtained. Other outstanding issues are listed in Section 5.

A listing of the characteristics of existing and planned energy storage installations and a brief description of the algorithm used for the analysis of the illustrative system in the load leveling mode are presented at the end of the report.

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1. Introduction

Background

Electrical energy should be consumed at the same instant that it is produced. Unlike other forms of energy such as natural gas or oil, which can be stored without changing its form, large quantities of electrical energy cannot be stored. Therefore, electricity has to be produced at the same instant that it is needed. Small amounts of energy can be stored in batteries in the form of direct current (dc) energy due to electrochemical action. Research efforts are presently directed toward increasing the energy density in batteries, in hopes of making large amounts of electrical storage economical.

Some large-scale storage installations have been economically justified by the dynamic provided benefits to the utility system; an example of such an installation is in Puerto Rico [1]. Instead of storing electrical energy, energy stored in other forms that is readily converted to electricity offers many advantages and opportunities. For instance, hydroelectric generation in a system offers energy storage possibilities. Holding back water is de facto energy storage in the form of potential energy in the impounded water. The potential energy can be readily converted to electricity without a thermodynamic process. The pumped storage plant is a prime example of large-scale energy storage in operation today. Many North American electrical utilities own and operate such storage plants to realize large economic benefits. Another form of storage is storing heat, i.e., storing heat in a central location and converting it to electricity through a thermodynamic process. Another example is that of storing heat (or cold) at the end-use application. Some of these technologies will be addressed later in this report.

Recently, however, advances in semiconductor and power conversion technology have drawn attention to battery energy storage once again. Furthermore, anticipated developments of advanced batteries for electric vehicles (EVs) are expected to make a significant impact on the storage of electrical energy in the electric utility system as well. Recent concerns regarding environmental and other issues have led to serious consideration of renewable energy technologies as an alternative to the conventional methods of electricity generation. Commingling storage with renewable energy technologies (RETs) would mitigate or even overcome the disadvantages associated with the intermittence of RETs. Consequently, there is a rebirth of great interest in storage applications.

Our primary objective is to describe the state of the art of storage technologies and their performance and economics. Additionally, we would like to examine the anticipated effect of storage on renewable energy technologies such as solar and wind.

Scope

We will begin by describing the benefits of any storage technology in a electrical utility system. Subsequently, we will present a description of storage technologies considered to be promising and present their performance parameters. The ensuing sections discuss the effect of storage technology on RETs, followed by a listing of some outstanding issues. Finally, we briefly outline existing and planned installations of electrical energy storage.

A clarification regarding the terminology used in this report is pertinent. There are many forms of energy storage. In principle, storage can be divided into two categories: storage of electrical energy and storage of energy in other forms. Examples of the latter are heat storage and hydrogen storage obtained by the electrolysis of water using off-peak energy. In the following sections, the term "storage," without any qualification, refers to storage of electrical energy (e.g., energy stored in batteries) or storage of energy

that can readily be converted to electricity without a thermodynamic process (e.g., pumped storage plants). Other forms of storage (e.g., heat storage) are clearly indicated or are clear from the context.

This report focuses on intermittent renewable energy technologies (IRETs). These are technologies, such as wind power and photovoltaic (PV) generation, whose output varies, depending on the resource characteristics, and is subject to daily and seasonal variations that cannot be predicted a priori. The disadvantages associated with their intermittence can be mitigated by storage. There are other renewable technologies, such as biomass steam-generated electricity and hydropower, that are not different in their operating predictability and characteristics from conventional technologies. Therefore, the output of such technologies is not intermittent.

Organization

Sections 2 and 3 discuss various benefits obtainable by installing storage in utility systems and storage technologies. Readers familiar with these issues may proceed directly to Section 4, which discusses the relation between storage and renewable energy technologies. The benefits from a particular mode of operation can be maximized by selecting an optimal kilowatt-hour and kilowatt capacity for storage. Presumably, such an optional capacity is influenced by the penetration of IRETs. Section 4 examines the operation of storage in the load leveling mode and the effect of IRETs on the benefits in such a mode of operation. The details of the study using an illustrative system and the computation procedure are shown in the appendices. Section 5 suggests further areas of investigation. Section 6 is a brief listing of existing and planned utility storage installations. A brief discussion of capacity credit and the details of the illustrative system studied are also included in the appendices.

2. Benefits of Storage in Electric Utility Systems

There is copious literature on the benefits of storage to particular utility systems. In addition, there are research reports from the Electric Power Research Institute (EPRI) outlining several benefits and aspects of these benefits. Our purpose is neither to summarize all of the studies nor to repeat and critique the literature. The intent here is to describe possible benefits under broad categories to familiarize the reader. The benefits are described in conjunction with a succinct summary of major research efforts and publications.

Load Leveling

The demand on a electric utility system is temporal in nature. Figure 1 illustrates a system in which peak demand occurs during the evening hours.

The resources of the utility consist of several generating units with different operating and capital cost characteristics. Those with the lowest operating cost are operated for the longest time. This is illustrated by unit 1, called the base load unit, which is operated throughout the day at full output.

Next in this illustration are units 2, 3, and 4. Unit 2 is operated throughout the day, but the load on this unit is less than full load during the period from 0 (midnight) to 3 a.m. Unit 3 picks up load or is dispatched at 3 a.m. and is loaded fully at 5 a.m. Unit 4 is at full load at 6 a.m., and unit 5 is at full load at 9 a.m. It is clear from the figure that other units are dispatched as needed at the appropriate times to meet the demand. Unit 7 is dispatched only during the peak load hours of 4 p.m to 8 p.m. Hence, it is called the peaking unit. Similarly, unit 6 is also classified as a peaking unit because its operation is restricted to peaking hours. Unit 6 is not dispatched between the hours of 11 a.m and 1 p.m. It is redispatched from 1 p.m until 9 p.m. The operating times of the other units are clear from Figure 1. Units 2, 3, 4, and 5 are termed cycling units because the load on them varies with time.

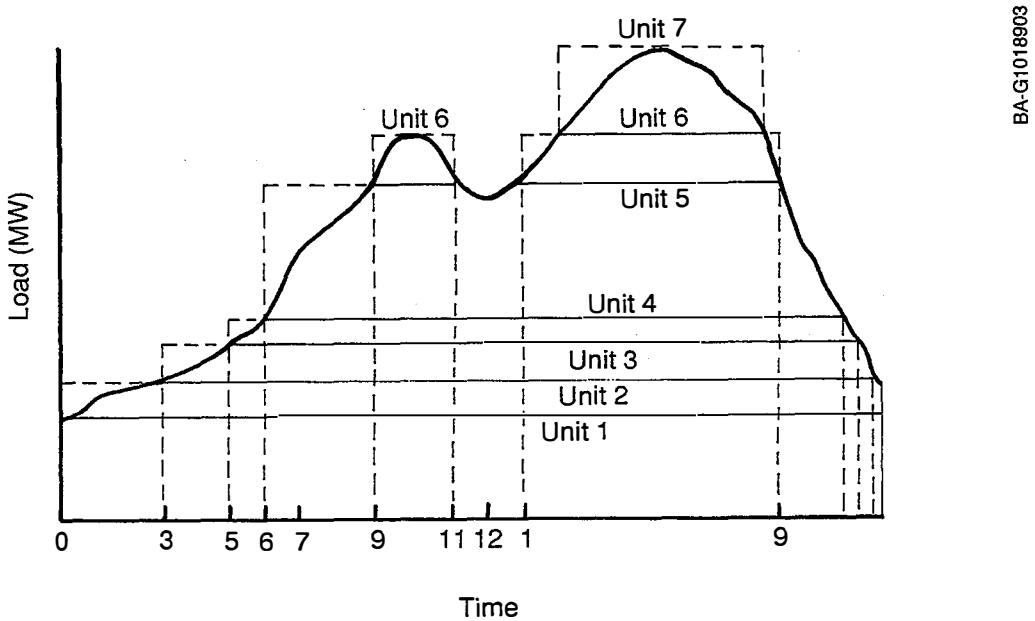

Figure 1. Portrayal of generating unit dispatch during a day

The unit with the highest operating cost (a product of the heat rate times the cost of fuel per heat unit, plus other variable operating and maintenance costs) should operate for the shortest time to realize the maximum economy. The peaking unit has the highest cost of operation per unit of energy output, followed by unit 6 and other units farther down in the dispatch order.

It is clear from the above discussion that the marginal cost of electricity, often denoted by λ[1], in the shorter time frame is a nondecreasing function of demand because of the way the generating units are dispatched. Consequently, λ increases with system demand.

Therefore, the motivation for load leveling arises as follows. If extra energy is produced and stored during periods of lower lambda, it can be withdrawn from storage during periods of higher lambda. Thus, during high load periods, dispatching peaking units is reduced. In fact, this is the mode of operation of all pumped storage systems that work on a daily or weekly cycle.[2]

Note that the load leveling mode of storage operation enhances the capacity factor of base load units, and permits the energy produced to be used during the peak load period. The use of premium fuels (oil/gas) normally used to serve peak load is therefore reduced, resulting in less electricity supply costs.

The economic justification for load leveling installations should consider the costs associated with the storage installation against realizable benefits. In addition, the cycle efficiency of the storage system is an important factor in the benefit calculation, as well as in the operation. The cycle efficiency is the ratio of net energy expended to the net energy recuperated or drawn from the system. For instance, if the cycle efficiency is 0.7, there would be no point in storing energy, unless the λ is 0.7 times or less than the peak λ (or the λ at the intended draw-down period).

Another application of load leveling addresses the reduction in the difference between the peak and off-peak loads in selected transmission and distribution (T&D) circuits, as opposed to those of the whole system. This will be addressed later under the heading of "Control of Line Loads."

T & D Benefits: Deferral of Line or Circuit Upgrades—Mitigation of Line Overloads

Consider a distribution or a subtransmission line to be a radial line, for simplicity's sake. A radial line is one that emanates from a substation and terminates at the bus of the load it is intended to serve. There are no tap-offs or other connections along the length of such a line to connect or mesh the line with other parts of the transmission or distribution network. The demand pattern of the load has temporal variations resulting in a peak demand at, say, 3 p.m. The distribution line has to be designed to stand the peak load and is underloaded at other times of the day.

Suppose the demand growth necessitates an upgrading of the line in 5 years. The upgrading may take the form of reconductoring, an increase in line voltage, the installation of bigger transformers, or all of these initiatives. Normally, such upgrades are expensive.

The line upgrade can be deferred and even avoided by one or more demand-side management (DSM) initiatives. One such initiative is the installation of energy storage devices at the end of the line in close electrical proximity to the load point. As will be explained later, the storage device can be electrical (such

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[1]In this discussion, λ includes just the cost of production. It could include many other complex components, especially for longer run marginal cost calculations.

[2]The pump storage units are called on to pump (store energy in the upper reservoir) during periods of light load, e.g., nights or weekends or both. The energy in the reservoir is depleted during periods of high load.

as batteries), or can be other forms of storage, such as heat and cold storage. In essence, the installation of storage will permit the charging or storing of energy during light load hours. The stored energy is used to feed all or part of the load during high demand periods. The net result is that the load on the line in question during peak demand periods would be reduced. In other words, the temporal nature of the load on the line will have less variations. Consequently, upgrading the line, necessitated by the growth in peak demand, can be deferred or avoided. Of course, the costs associated with the installation of storage devices has to be less than the cost of upgrading. In addition, there might be other benefits in avoiding line upgrades.

It is important to note that the installation of storage devices can only permit the deferral of "upstream" facilities. By upstream facilities, we mean facilities from the storage device toward the source of energy supply. Such delineations of upstream or "downstream" facilities are clear in radial lines and networks. Such a characterization is somewhat complicated in meshed nonradial networks. Nevertheless, in meshed networks, it is possible to determine the path of power flow from load flow analyses. Hence, facilities that carry power flow to the storage location can be considered upstream facilities. Facilities that carry the power away from the node where the storage device is located are considered downstream equipment.

The above argument regarding deferral of equipment upgrades applies to transmission facilities as well. In that case, one considers installing electrical storage at suitable points in the transmission network to obtain benefits.

Dynamic Benefits

Storage installations can be used to provide dynamic benefits to the power system. In such applications, energy (joules) is released into or absorbed from the system in a very short time, in the order of milliseconds. Such installations either avoid or defer the installation of additional generation or transmission-related capacity, such as gas turbine generators, static var compensators, and the like. In most instances, electrical energy storage can be operated and controlled to behave as a surrogate for generation. A description of some benefits by such control actions is given below.

Frequency Regulation

The governors of the generator prime movers keep their speed, and therefore, the system frequency constant. Consequently, the load demand on the system and the energy input to the prime movers are kept in balance. However, this equilibrium is upset when the demand on the network changes. Under those circumstances, the response of governors is set so that a sudden increase in demand causes a small reduction in frequency and vice versa. This characteristic, called the "droop," is necessary for the satisfactory operation of all generators together in a network.

Some generating units on the system are put on automatic generation control (AGC) to hold the frequency constant. These generators sense the drop of frequency and readjust their governors to allow more input energy to the prime movers in order to hold the load and frequency constant. This mode of operation is also called load frequency control (LFC). During normal system operation, some generators are assigned the task of frequency control.

The task of frequency control can be assigned to or shared by electrical storage devices that have a fast response time. For instance, in a battery storage installation, the stored energy in the battery can be injected into the network when the imbalance between the demand and the generation results in a deficit. Similarly, when there is a net instantaneous excess, the excess energy can be absorbed in the batteries. In other words, the storage installation functions as a fast-acting generator under LFC.

In interconnected system operations, instantaneous imbalances between demand and generation are compensated for by the flow of assistance power in the tie lines from the neighboring system. Thus, the fluctuations of frequency that would otherwise result are mitigated by tie-line power flows. In isolated systems or in systems with weak interconnections, such fluctuations could be more than permissible, calling for the installation of additional generation, such as gas turbines, to perform the LFC function.[3] In some instances, electrical storage devices (batteries) are found to be more economical than installing additional generation.

Spinning Reserve Benefits

In a well-operated system, a certain percentage of the generation is held as operating reserve to cover fluctuating demand and situations of generating unit outages, or other contingencies, such as the outage of major transformers or transmission lines. According to the operating guidelines of the North American Electric Reliability Council (NERC), each utility is required to carry spinning reserve that responds to AGC, to meet the anticipated load fluctuations plus an additional amount of reserve sufficient to reduce the area control error to zero within 10 min.[4] At least 50% of the operating reserve will be spinning reserve that will automatically respond to frequency deviation.

Note from the above text that one-half of the reserve is spinning and synchronized to the system, while the other half should be dispatchable within 10 min. The synchronized spinning reserve could be the spare capacity in the machines under LFC, as discussed earlier. In that sense, the synchronized reserve capacity is in the LFC mode of operation.

Fast-acting electrical storage systems can serve the purpose of synchronized spinning reserve and even that of callable 10 min. reserve. The storage devices have to be kept charged for this mode of utilization. They are controlled to input into or absorb energy from the system just as any generator under LFC. Studies indicate that lead acid batteries serve this function well and offer a cheaper alternative to the traditional method of installing operating reserve by installing gas turbine generators [1,2]. Reference 3 quantifies the benefits when storage is dispatched to enhanced spinning reserve.

Transient Stability Benefits

Faults or other severe disturbances in the electric network cause an imbalance between the input energy and the output of generators. Therefore, such disturbances cause an acceleration or deceleration of the rotating masses. Because all of the masses in generators may not accelerate or decelerate equally, out-of-phase swinging or oscillation among rotational masses results. After the fault or the disturbance is isolated by appropriate relaying action, the changed condition of the network alters the postdisturbance energy output from their predisturbance values, thus contributing to further swings in rotor angles.

Of course, under most circumstances, the system is designed to overcome the disturbance by damping out the oscillations properly. The damping arises from synchronizing power flow from speeding masses to slower masses, via the network impedance, giving rise to eventual synchronous rotation of all masses. However, under very severe circumstances, or if the line impedance between the generators is high, the flow of synchronizing power is inadequate, leading to the loss of stable synchronous operation. Such a condition is detected by relays, and isolation of the system to smaller sections (called islanding) or a cascading network blackout could be the end result.

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[3]Without such corrective actions of installing more generation or electrical storage under LFC, shedding of some loads in the case of underfrequency, or generation in the case of overfrequency, would be required.

[4]Area control error (ACE) is defined as the sum of the scheduled imports and exports.

Utilities plan for such exigencies by studying the network for different contingencies. Such studies, called transient stability studies, are performed routinely, using well-accepted software. The results of such studies point to the required system changes such as the upgrading of lines to reduce the impedance for the flow of synchronizing power, or the installation of other control equipment.

Storage devices that are fast-acting offer an alternative. Their installation and control at appropriate locations in the network will permit the supply of energy to slower masses, or the absorption of energy from faster masses. In addition, the presence of the storage equipment reduces the line loads during the peak load period as discussed earlier. As a result, proper control of the storage scheme can enhance the transient stability. Indeed, looking at this another way, storage devices can be considered as an alternative to upgrading network and other facilities to achieve or enhance stability. The installation of storage could be a more economic proposition than the traditional methods of upgrading the network.

An EPRI report [4] shows the benefits of transient stability improvement in an illustrative transmission system.

Unit Commitment and Load-Following Benefits

One of the tasks of operating personnel is to schedule generating units that are to be started and stopped to meet the day-to-day demand at minimal cost and acceptable reliability. The procedure of planning unit start-ups (and shutdowns) for the next few days is called "unit commitment." Thermal generating units require a finite time to pick up load. Large fossil units take several hours from a cold start to pick up load. If such units have been kept hot by "steam jacketing," they take less time to pick up load. Some thermal units, particularly smaller combustion turbine units, can be loaded in a relatively short time. Hydro units can pick up load very quickly, in just a few minutes.

There are costs associated with starting and stopping units. Starting larger fossil units involves many hours and requires calling a crew several hours before the unit is expected to pick up load. The start-up and shutdown costs are a significant portion of the operating cost.

Thermal generating units have another restriction, called the rate of loading or "ramping rate." The rate of load pickup per minute cannot exceed a certain value, generally 1% to 2% of the nameplate rating per minute.

Almost always, unit commitment is made for the next week with daily updates. The forecast demand for the next day is allocated among the candidate units to minimize production and start-up costs while maintaining adequate reliability. The commitment procedure specifies times at which particular units are to be started/stopped, their rate of loading, the amount of spinning reserve required to perform LFC, and other such operating details. The demand on the system is followed, or met, during the next day by following the procedure outlined in the commitment plan.

The advantage of storage is that it could be used to reduce the total production cost. It might be possible to avoid starting and stopping some units by drawing energy from storage, or by putting energy into storage. Similarly, the ramping rate restrictions on units can be accommodated by using energy from storage. Consequently, substantial savings could result by avoiding starting and stopping units that might be required without storage. Such benefits, under the general category of dynamic benefits, are called "load-following benefits."

Strategic Applications

Recently, installing storage devices to obtain strategic advantages has been considered. Although there is no installation that is justified for these reasons at present, it is possible that the impact of the Clean Air Act Amendments (CAAA), PUCHA reform, wheeling, and other regulatory initiatives will catalyze interest in this application of storage devices.

In terms of the CAAA, it is conceivable that energy from cleaner generation will be stored and depleted at times when dirtier plants would have run. Effectively, such an operation will increase the load factor on cleaner sources at the expense of dirtier plants.

Other strategic benefits are bandied about. One is that of storing energy and offering it for sale in the futures' market to maximize benefits or to sell emission credits. In fact, some pumped storage units in the country are used in a "buy low-sell high" mode in a power pool. At present, the impact of such applications on the market for storage devices is unclear. Such applications are driven by the future technology of storage, its cost vis-à-vis the market for emission credits, environmental concerns, and energy costs.

DSM and Customer-Side Applications

In this category is the installation of storage devices at the load point of the consumer, preferably by the consumer at the consumer side of the bus bar. The storage devices would be charged during the off-peak hours and will be discharged to minimize the maximum demand of the consumer during times of the consumer's (not necessarily the system's) peak demand. Both the utility and the consumer benefit from such an installation. The incentive for the consumer is that the consumer could save on demand charges at the expense of slightly increased energy charges arising from the cycle efficiency of the storage device. Obviously, the demand charges have to be high to warrant the economics of such installations. An installation in Colorado has been justified on this basis [5]. The gain to the utility is that of an increased load factor on the distribution feeder and reduced losses.

EPRI indicates in a 1984 report [6] that the demand charge of about $10/kW/month is the minimum for economic viability of such schemes. Needless to say, these figures could change, depending on the development of storage technology and the generation mix of specific utilities.

There are a host of other possible customer-side installations of storage devices. Such applications are generally classified under power quality improvement, e.g., mitigation of voltage surges and short-term interruptions. The main application is in uninterruptible power supplies (UPS), which consist of a battery and power conditioning equipment (inverter). UPS have been available in the market as a standard off-the-shelf product for quite some time. When the supply fails, these devices provide backup power. Such devices are also used to minimize voltage surges and spikes by those desiring a high power quality. Superconducting magnetic energy storage (SMES) is preferred as the medium of storage in such power quality improvement applications because of its very fast response, low maintenance expenditure, and smaller "footprint," including the refrigeration equipment, compared to batteries.

The benefit to the consumer is that of loss minimization because of interruptions. A greater deployment will occur if UPS permits planning the distribution system at a lower reliability level, thus reducing costs to the utility.

3. Storage Technologies

The following is a brief description of storage technologies, their operating characteristics, and their costs. The costs of these technologies vary from installation to installation. In most instances, the cost data are taken from the EPRI *Technical Assessment Guide (TAG)* [7].

The cost of storage installations is generally expressed as an aggregate of two distinct components: the power component and the stored energy component. To clarify this further, consider the example of battery storage. The power component relates to the cost of the alternating current/direct current (ac/dc) converter interface. The energy cost relates to the amount of energy that can be stored.

If the stored energy is discharged in 3 h, one refers to it as a 3-h battery. In general, a 3-h battery tends to be more expensive than, say, a 7-h battery. This is because of the higher currents involved in the 3-h battery, necessitating bigger terminals and other components in the conducting path. There are other nuances arising from electrochemical reasons that are beyond the scope of our discussion.

The cost C, in dollars per kilowatt, is expressed as

$$C_t = C_p + C_s \times t$$

where

C_t = total plant capital cost ($/kW)

C_p = cost of power component ($/kW)

C_s = cost of stored energy component ($/kWh)

t = storage time (h).

Considering the above equation in relation to pump storage plants, note that C_p represents costs associated with the capacity rating of the turbine generator unit, and C_s represents costs associated with the storage reservoir.

In the following discussion, the costs of different technologies are expressed in these two distinct categories. Clearly, these two cost elements are important design parameters. Storage design is based on careful consideration of system requirements and the expected storage operation. The goal of an optimal design is to obtain maximum benefits. The results of a study to optimize benefits in an illustrative system are outlined in Section 4.

Pumped Storage Plants

Conventional pumped hydro consists of an upper and a lower reservoir of water. In the pumping or charging mode, water is pumped from the lower reservoir to the upper reservoir. In the discharge mode, water is discharged through the reversible turbine generators to produce power. Underground pumped hydro installations are similar to conventional installations, except that the lower reservoir is located underground.

The maximum response time is about 50% of its nameplate rating per min. This response time is adequate to perform regulating duties as assigned by the AGC as in any conventional hydroelectric unit. However,

the response time may not be fast enough to reap some dynamic stability benefits that are possible from an SMES or battery storage system.

The amount of energy stored in the reservoir is related to the quantity of water held and the head. The capacity of the turbine/pump generator determines the time during which this energy can be discharged or charged.

Several pumped storage plants have been in operation in utility systems for many years. This is a well-proven technology. Most installations have been justified, based on load leveling benefits. The storage facility is operated on a weekly or a daily charge-discharge cycle, the former being more common in locations with substantially large storage in the upper reservoir. In the weekly cycle of operation, the upper reservoir is charged mainly during weekend low-load hours. In the daily cycle of operation, night-time low load periods are designated as the pumping hours. The discharge in either mode of operation is during daily high-load periods.

The cycle efficiency depends on the load level of the plant [7]. However, an average annual efficiency of 73% is suggested in the TAG.

Pumped storage plants require special terrains that permit the construction of an upper and a lower reservoir. Consequently, the costs are site specific and depend on the civil work involved. The cost of installations could vary by as much as 40%. The costs suggested for the Northeast installations are $700/kW for power charging-discharging and for 10 h of operation, $117/kW for storage costs.

Battery Energy Storage

These installations consist of a bank of batteries and the associated power conditioning equipment to convert from ac to dc for charging, and vice versa. At the time this report was written, commercial installations consisted only of lead acid batteries. However, the technology of system design is easily applicable to advanced batteries. It is generally believed that advances in battery research for electric vehicles will have applications and "spin-offs" in the area of utility energy storage.

A reliable and successful battery storage installation requires the careful consideration of several design factors. In addition to optimizing the benefits of integrating the storage with the system, proper design of the batteries to suit a particular duty cycle of operation is essential to ensure trouble-free operation and the economic life of the system. First, the proper capacity and energy requirements should be selected, based on a study of system benefits. Such a selection is based on an expected mode of operation that determines the duty cycle. The duty cycle determines the design parameters for the battery and the converter. It is not uncommon to examine alternative designs in the conduct of cost benefit analysis of such systems.

We will outline some important considerations in the design. Obviously, a brief explanation does not do justice to the design process, which is highly specialized. Nevertheless, such a discussion will offer an insight into some major design considerations.

Footprint

The size of the building required to house the system influences the cost to a considerable extent. As will be seen later, although the cost of conversion equipment is a substantial portion of the total cost, the physical size of the conversion equipment compared with that of the batteries is very small. Therefore,

the energy density[5] in the batteries and their physical arrangement influences the footprint and consequently, the balance of plant costs of the storage system.

Life

Lead acid batteries have a finite life. First, their shelf life varies from 10 years at 20°C to about 0.3 years at 60°C [2]. Furthermore, the life of lead acid batteries in the operating mode depends on the depth of discharge. The number of charge/discharge cycles to failure varies from about 200 cycles at 100% depth of discharge to about 5000 cycles for discharge depths of 25% [2]. Therefore, in the cost benefit analyses, one has to account for battery replacement costs.

Efficiency

The efficiency of batteries is generally expressed as charging efficiency and discharging efficiency because of somewhat different electrochemical processes involved during charge and discharge. A combination of the two is expressed as the cycle efficiency or the turnaround efficiency given by the ampere hours withdrawable, divided by the ampere hours put into the battery. From a system design point of view, one is generally concerned with cycle efficiency, commonly referred to as "efficiency."

The efficiency of batteries is a function of charge/discharge current. It varies from about 80% at full power to about 85% at 20% power. Since resistance losses are proportional to the square of the current, at higher currents, the internal losses are disproportionately larger. A degradation of efficiency results when batteries are overcharged. The round-trip efficiency of lead acid cells drops to about 75% at 115% recharge.

Maintenance

There are two different designs of lead acid batteries: the flooded cell and the sealed valve, regulated starved-electrolyte type. The former is the traditional design and requires periodic maintenance to make up for the loss of electrolyte. The latter type has no loss of electrolyte, and each battery is put in a sealed container. Therefore, it requires less maintenance. Both design types require periodic checks for failed cells and require other maintenance that is routine in any electrical installation. In terms of costs, however, sealed cells cost about 110% as much as flooded cells.

Cost of Installations

As discussed earlier, there are two components of cost: C_p and C_s. These components for heavy-duty lead acid batteries[6] are \$325/kW and \$127/kWh, respectively [2]. For light-duty batteries, the corresponding numbers are \$260/kW and \$76/kWh. In addition to these components, balance of plant costs of \$375,000, and \$300,000 have to be added for heavy-duty and light-duty installations.

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[5]The energy density in the lead acid cells at present is in the range of 80 to 90 kWh/kg. This figure is expected to improve in the future because of research and development (R&D) efforts. In particular, advanced batteries have already demonstrated substantially higher densities than lead acid batteries. The energy density expressed as the area required to house the batteries is in the range of 1 to 5.25 kWh/ft^2 in existing installations. This variation arises from the differences in the physical arrangement of the batteries such as single layer, double layer, etc.

[6]There is somewhat of a fuzzy definition for heavy-duty and light-duty batteries. However, it is generally agreed in the trade that heavy duty refers to batteries designed to be frequently and deeply discharged (i.e., 200 to 250 cycles per year and 60% to 80% depth of discharge). Similarly, light duty refers to infrequent discharges, deeply or otherwise (i.e., 50 cycles per year). Some applications of storage may fall between the two categories.

Example: Let us estimate the cost of a 1-MWh 5-h heavy-duty installation.

Capacity of Converter	=	$1.\ 10^6 \div 5 = 200$ kW
C_p = 200 kW x 325 $/kW	=	$ 65,000
C_s = 127 x 1000	=	$127,000
Balance of plant	=	$375,000
Total		$567,000

The cost of a device for the same energy, but for a 2-h charge discharge time (the higher rate involves a converter of increased capacity), changes the C_p component to:

$$Cp = 325 \times 1000 \div 2 = \$162{,}500.$$

It is generally held that the capacity component of the cost could decrease in the future, resulting from modular and improved inverter design and from reductions in the cost of solid-state devices and controls.

Superconducting Magnetic Energy Storage Systems (SMES)

In this technology, electrical energy is stored in the magnetic field of a coil, either solenoidal or torroidal in shape. The current in a coil with zero resistance and short-circuited terminals, once established, does not decay and flows forever. Hence, energy is stored in the magnetic field of the coil. It is equal to the product of half the inductance of the coil and the square of the current. The coil itself is under a tremendous force. Consequently, it has to be properly supported. One common method is to bury it underground. Such installations are termed earth-supported coils.

The resistance of the coil disappears when it is kept at superconducting temperature. Current in the coil is established by applying a constant dc voltage when the current builds up linearly with time. The buildup of current establishes a field in which energy is stored.

A conductor, in order to remain in the superconducting state, must satisfy three conditions. The first condition is that the temperature must be below a critical temperature. The second condition is that the current density in the conductor must be below a critical value. And finally, the magnetic field in the conductor should be below a critical value. If any of these conditions are violated, the conductor switches from the superconducting state to the normal state.

The coil temperature is controlled by a properly designed refrigeration system. The control of the other two critical parameters is achieved by proper design. Presently, a commonly used superconducting material for the coils is Nb-Ti, which is superconducting at temperatures of 4.2 K. This temperature is maintained by cooling the coil with liquid helium.

Some utilities and other organizations, including the Bonneville Power Administration, have demonstrated the feasibility of SMES through several experimental installations. Reference 8 is a good source of the present state of the art and includes a description of major experimental installations. The so-called micro-SMES is a small installation capable of discharging high power for a duration of 10 to 60 cycles to improve power quality. Such a device is available commercially and has been installed in three locations.

Efficiency and Cost Estimates

The efficiency of SMES is expected to be well over 90%. Because this is not a well-established technology, the cost estimates vary. According to one source [9], the total cost of a 7300-MWh, 1800-MW installation is estimated to be $1,161/kW in the short term and $778/kW in the longer term. The short-term and longer term estimates by the same source for a 15,000-MWh, 250-MW installation are $1,196/kW and $700/kW. Present efforts in the development of high-temperature superconductors are expected to reduce the cost of SMES.

The response time of SMES is very fast, on the order of milliseconds. Therefore, such installations are well suited to obtain dynamic system benefits.

Compressed Air Energy Storage Systems

The concept of compressed air energy storage (CAES) for utility applications is to store energy in a large volume of air in underground caverns. CAES is suited for load-leveling applications.

The process uses electrical energy during off-peak periods to compress and store air in an underground geological formation. The compressor is driven by a synchronous motor that can also be used as a synchronous generator during the discharge mode.

During the discharge mode, air from the cavern is used in a gas turbine fueled by natural gas or oil. The combustion turbine drives the motor generator in a generating mode, feeding energy to the electrical grid. The advantage of the process is eliminating what is termed as compressor penalty. A conventional combustion turbine has a built-in compressor on the same shaft to provide the required air for combustion. The energy required for air compression is about 60% of the total energy consumption. The heat rate of conventional combustion turbines range from about 10,500 Btu/kWh to about 13,000 Btu/kWh. The injection of air previously compressed using off-peak energy in turbo-compressors improves the economics of the process. No air compressor on the shaft of the combustion turbine would be required. The removal of the compressor penalty by using previously compressed air means that the heat rate of the combustion turbine will drop to about 4300 Btu/kWh. The total cost of energy recovery is the off-peak cost of electricity times the kilowatt-hours used for air compression, plus the cost of fuel per Btu, times the Btu used to generate electricity. Clearly, the total cost is less than the cost of generation in a conventional combustion turbine.

Cost

One crucial factor that impinges on the cost is the location of the CAES plant [10]. The proximity to transmission and the availability of an underground reservoir for storage are the key issues.

Three types of geological cavities can be adapted for use as reservoirs—salt dome, hard rock cavern, and aquifer.

The formation of a salt reservoir cavity is the least expensive. The reservoirs are formed by a commercially available mining technique known as solution mining. Water is pumped into the salt dome formation. Water dissolves the salt and the resulting brine is pumped out for disposal or use in a secondary chemical plant.

Forming a hard rock cavern is considerably more expensive than the salt cavity. Aquifer caverns are sandstone formations that are believed to be widely available in the United States.

The EPRI TAG [7] suggests the following cost estimates for a 10-h storage installation: $390/kW for charging and discharging plus $124/kW for 10 h of storage, bringing the total cost of the plant to $514/kW.

Efficiency

The costs of energy recovery at different loads are suggested in reference 7. For example, at full load, obtaining 1-kWh output would require 0.76 kWh for compressing the air and 4280 Btu of thermal energy into the combustion turbine.

Flywheel Energy Storage

The basis of the concept is simply to store energy in a rotating mass. However, several design parameters have to be optimized to reduce the cost of such installations. The first is that of building efficient flywheels that are strong enough to withstand inertial forces in compact designs. Another aspect is that of minimizing friction losses in conventional contact bearings at high speeds. Magnetic suspension bearings have been suggested and studied. Research examining these issues has been conducted. An example of such a design effort is found in reference 11.

There has been no large-scale utility installation of this storage medium in the United States. Consequently, it would be difficult to suggest efficiency or cost figures based on experience. However, Kirk and Anand [11] suggest the following figures for modules of 24 kWh designed for residential installations for load leveling. The upfront cost of the device is $7,500, and the round-trip efficiency is 81%. The capacity of the device is 2.5 kW. The cost breakdown into capacity and energy components is not shown in the article.

Summary of Costs

Table 1 shows a comparison of costs of some major storage technologies discussed earlier. The cost projections in the table are slightly different from those given in connection with the discussion of technologies. Nevertheless, Table 1 and the earlier discussion indicate the range of cost values for different storage technologies. There is a certain degree of variability in these cost figures, depending on the characteristics of the site and systems.

Table 1. Estimated Costs for Energy Storage Technologies
(in constant 1989 dollars)

Technology	Power-Related ($/kW)	Energy-Related ($/kWh)	Hours of Storage	Total Cost ($/kW)
Compressed Air				
Small module (25-50 MW)	575	5	10	625
Large module (110-220 MW)	415	1	10	425
Pumped Hydroelectric				
Conventional (500-1500 MW)	1,000	10	10	1,100
Underground (2000 MW)	1,040	45	10	1,490
Battery				
Lead-acid (target) (10 MW)	125	170*	3	635
Advanced (target) (10 MW)	125	100	3	425
Superconducting Magnetic (Target) (1000 MW)	150	275	3	975

*Lead-acid battery cells must be replaced after about 15 years at a cost of about $85/kWh for 250 cycles/year duty.

Source: *Energy Storage: How the New Options Stack Up*, EPRI GS.3002.6.89 [12]

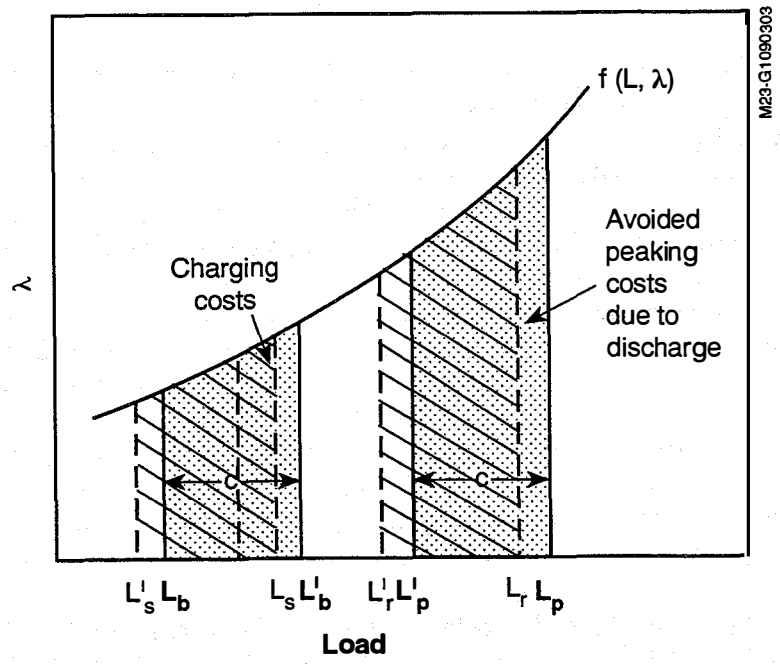

Figure 3. Charging costs and discharging benefits

can examine the load leveling mode of operation, keeping in mind that the charging occurs at low (hence, low cost) periods and the discharging occurs at high load periods.

Suppose the load at some peak period hour is L_p. If the storage device of capacity C is discharged at this hour, the net load reduces by C to a value L'_p. The energy drawn from storage in this hour is equal to C times 1 h = C. The avoided cost of generation (benefit) is given by the area under the $f(L,\lambda)$ curve between the limits L_p and L'_p, expressed as

$$\int_{L_p}^{L'_p} f(L,\lambda) \ .$$

Similarly, the addition of a charging load of magnitude C at an off-peak time when the load is L_b results in an incurred cost represented by the area under the $f(L,\lambda)$ curve between the limits L_b and L'_b. The difference between these two areas represents net benefits. The energy put into storage during the hour is also equal to C. To account for the cycle efficiency, either the capacity of operation during charging has to be greater than C or the charging process has to last more than an hour.

To compute the annual net benefits, all the charging and discharging hours have to be considered. There are several methods available to perform such computations efficiently. Appendix 2 outlines the study conducted by using a digital computer program developed at NREL on an illustrative system.

It is easy to see that there is an optimum for kilowatt and kilowatt-hour of storage capacity. If too little capacity for storage is allocated, neither the specified energy can be stored during the off-peak hours nor

can the specified energy be discharged during on-peak hours. On the other hand, if too much capacity is specified, the two areas in Figure 3 overlap during some hours, indicating that the system marginal cost while discharging can be lower than that during charging—an undesirable situation.

Effects of Penetration of Renewable Technologies

Consider the infusion of energy into the system. The injection of energy can be from IRETs or other sources such as IPPs, QFs, and the like. The injection from the former two categories has to be absorbed into the system as and when available since the marginal cost of energy from these sources is almost zero. The infusion from the latter sources can be controlled. In that sense, they resemble dispatchable resources.

If the energy from an IRET occurs at the time of peak load, the system marginal cost decreases. Hence the benefit due to the discharge of an already existing or contemplated storage is now represented by the area under the curve between L_r and L'_r, which is to the left of the area representing the benefit without the infusion. Clearly, the discharging benefits will be reduced. Note that the difference L_p–L_r represents the capacity of infusion from IRETs.

Similarly, infusion of energy during off-peak hours also reduces the system marginal costs. Therefore, the cost of storing energy also decreases. This is represented by the area under the curve between L_s and L'_s, to the left of the previous cost area between L'_b and L_b.

Since the benefit is given by the difference between the two areas, it is evident that the benefit due to the operation of storage in the load leveling mode decreases if the IRET output coincides with high load hours. If the IRET output is only during the low load hours, the benefits of storage operation would increase. If the output from the IRET is uniform during low and high load hours, the benefits of storage operation would decrease if the load lambda relation increases more than linearly. A linear relationship between lambda and load would keep the storage benefits unchanged for uniform IRET output during peak and off-peak load hours.

Results of Study

Appendix 2 shows the results of a study using an illustrative system. The system has a peak load of 3000 MW and an installed capacity of 3440 MW. Two demand profiles were assumed: peak demand occurring during the day, representing a predominance of air conditioning loads, and the peak demand occurring during the evening hours, typically 6:00 p.m. Two scenarios of IRET injection, either 100 MW wind or 300 MW of PV, were studied. Appendix 2 gives the details of the temporal nature of these injections.

It was found that while the system without RETs could benefit from load leveling storage, no benefits would accrue from storage with IRET injection. The exception was that of 100 MW wind energy in the daytime peak load scenario, when the benefits due to dispatching storage were positive, but less than the case without wind energy.

In summary, the load leveling benefits due to the dispatch of existing storage in a system decrease with the penetration of IRET sources. Similarly, it would be difficult to justify the installation of storage along with the IRET to derive load leveling benefits. These results are not surprising and should be intuitively obvious. Energy penetration from IRETs, or the penetration from other technologies such as DSM, over which the system operator has little control, in effect "flattens the load shape." Consequently, the opportunities for and benefits from load leveling would diminish.

Existing storage in a system is operated to maximize benefits. It is dispatched in different modes during different times of the day/year to maximize benefits. Since the benefits from the load leveling mode of dispatch diminish with the penetration of IRETs and other technologies, there will be an opportunity to operate the storage in different modes. An example of such a reoriented mode of operation is to dispatch storage in a reliability backup mode to mitigate the intermittency of IRETs.

A cautionary note regarding the above observation is in order. The scope of the present study did not include an examination of the optimum mix of different modes of storage dispatch as the penetration of IRETs increases. The results of such a study for other modes of operation could be quite different from the above. Consequently, it is imperative to study the effect of IRET penetration on different modes of storage dispatch before any general conclusions can be made. This study has shown an example of conducting such studies that are necessary to determine the effect of IRETs on storage technologies.

5. Outstanding Issues

In light of the previous discussion on storage technologies, their cost, and system integration aspects, the following issues emerge that need to be resolved.

Grid-Connected Installations

There are two distinct facets in estimating the benefits of storage: one from a planning perspective and the other from an operation's point of view.

From a planning perspective, one assumes certain operating scenarios and practices. But after the storage device is installed, it may be operated in a different manner. For instance, the market conditions in the shorter term are more apparent to the operator who will exploit the opportunities to derive maximum benefits. In contrast, the planner analyzing the benefits may not be able to foresee all the operational intricacies of the future. Therefore, it is important to ensure that the operational assumptions in the planning stage are as accurate as possible.

A storage device may be operated in a load leveling mode during a particular season and in a different mode, say load frequency control, in a different season. It might even be operated in different modes during different times of the day. Operation in some modes simultaneously is mutually exclusive. Clearly, operation in a spinning reserve mode, which necessitates the holding of charge or energy in storage, excludes a simultaneous operation of the same storage capacity in a load leveling mode, which requires discharges at times of high load. Consequently, it would be incorrect to compute and add the benefits of operation in more than one mode during the same period. Evidently, the total benefits are not a straightforward addition of different benefits. Because the penetration of IRETs reduces the benefits due to load leveling, it is important to identify and quantify benefits due to other modes of storage dispatch in a network. For instance, are the total benefits an arithmetical addition of the benefits from different modes of operation?

There are some well-developed software packages available for such analysis, mainly because of EPRI's efforts. It would still be beneficial to examine whether the disparate benefits are cumulative for installations at different locations in the network. For example, are the total benefits an arithmetical addition as the benefits from different modes of operation?

As pointed out earlier, the benefits from load leveling using existing storage decrease with increasing penetration of IRETs and DSM. Under such circumstances, it may be beneficial to reorient the operation of storage to that of a reliability backup to IRETs. It is necessary to incorporate such changes in operation into integrated resource planning methodologies.

Other benefits from storage arise from distributed installations. For such applications, it is important to investigate procedures to identify optimum locations. Presently, locations for storage or small generation sources are chosen in a somewhat arbitrary or ad hoc manner. Formalizing the selection of the optimal locations is preferable for such facilities. Optimality might be defined as minimization of loss, minimization of voltage sags, minimization of var requirements, minimization of capital for line upgrades, or any other chosen objective. A project that NREL undertook with its partners (DOE, Pacific Gas and Electric Co., and EPRI) addressed some aspects of this issue [15]. Additionally, an NREL project supported by overhead funds examined similar issues [16].

In a similar vein, the reliability of supply due to distributed installations is an important issue. For IRETs and storage installations, it would be necessary to establish methods to quantify reliability. The effort

would involve the input of resource characteristics and data (such as insolation and wind velocity) to estimate the reliability of supply to the end user, and to compare it with data obtained from conventional practices.

A corollary of this investigation would be comparing benefits from centrally installed RET resources with that of distributed installations. The former might require some storage, (e.g., thermal storage, as in the case of solar central receiver generation). In the latter distributed locations, one might require associated dispersed storage, in order to offer the same reliability of service and defer line upgrades at the same time.

Another important issue is the exploitation of benefits arising from system architecture by the collocation of technologies. For integrating the output of PV devices into the system, an inverter or other form of power conditioning equipment would be required. The same is true for electrical energy storage. Collocating these two technologies (or locating them in close proximity) will permit the use of shared power conditioning equipment. The benefits of such an architecture and its effects on system operation, reliability, and costs have to be examined.

Extending this concept further, it is also possible to install a combination of wind, PV, and electrical storage in close proximity. Although wind and solar resources are intermittent, it is unlikely that their intermittencies are correlated. It is also unlikely that both resources will be low or absent at the same time. Furthermore, wind and insolation may peak at different times of the day. Thus, there is an optimum combination of wind and solar generation to maximize the correlation with the demand pattern. The optimum mix of wind and solar generation depends on resource characteristics, demand, and the required level of reliability. Methods need to be developed to identify the optimum mix that results in the least-cost alternative in resource expansion plans.

The scope of this study did not cover the examination of required reliability-related storage, vis-à-vis the possible changes in the operation of existing storage facilities in a system. The inclusion of such reorientation of storage operation in resource expansion plans is an area of investigation that will shed light on the integration of RETs.

Isolated Locations

As discussed in Section 3, it is important to develop proper tools to optimally design a stand-alone RET system capable of modular expansion. This would involve optimizing storage to minimize the cost vis-à-vis the required reliability of service and resource availability.

6. Existing and Planned Storage Installations

In this section, we will highlight the main characteristics of existing and planned storage installations. There are several storage installations in Europe and other countries. It would be a formidable task to list all of them. Therefore, we will confine our attention to North America. In North America, there are several nonelectrical storage installations, such as heat storage in residences and industries. Our interest in this report is mainly on electrical storage; therefore, the following is a list of major storage initiatives consisting mostly of electrical storage.

Existing Storage Initiatives

1. Crescent Electric Membership Cooperative [17]

Primary application	Peak shaving Battery testing
Capacity	500 kW for 1 h (500 kWh) 300 kW for 2 h (600 kWh) 200 kW for 3 h (600 kWh)
Converter capacity 500 kW	DC voltage 750 V, interfaced by the converter to 480 V ac system.
Efficiency	72% ac-to-ac

2. Chino Battery Storage Project [18]

Primary application	Load leveling
Secondary application	Spinning reserve, load following, T&D deferral, economic dispatch, frequency regulation, voltage/reactive var support.
Utility	Southern California Edison
Capacity	10 MW, 40 MWh. Batteries are rated for 4-h discharge rate. DC voltage 1750-2800 V, interfaced by converter to 12 kV ac system.
Efficiency	72% ac-to-ac
Cost	$13,500,000

3. San Diego Battery Storage Project [19]

Primary application	Customer peak shaving
Secondary application	Spinning reserve T&D deferral Voltage/var control
Capacity	200 kW ac/420 kWH dc Converter capacity 200 kVA DC voltage 691 V-490 V Converter interface to 12 kV ac
Efficiency	Converter 93% at full power Battery 82% (2-h rate)
Cost	$1,442,858 (estimated cost)

4. Puerto Rico Electric Power Authority (PREPA) Battery Electric Storage System [20] [21]

Primary application	Spinning reserve and frequency control
Secondary application	Voltage/var support, black start operation
Capacity	20 MW, 14.1 MWh Converter rated at 20 MVA, interfacing to 13.2 kV ac system

5. Johnson Controls Battery Storage Project [22]

Primary application	Peak shaving
Capacity	300 kW/580 kWh (3-h rate) Converter rating 300 kW interfaces between 384 V dc to 480 V ac.

6. Delco Remy Battery Storage Project [23] [24]

Primary application	Peak shaving Battery testing
Secondary application	Alternative automobile battery use
Capacity	300 kW/600 kWh converter capacity 300 kW interfacing 600 V dc to 480 V ac.
Efficiency	74% to 86% ac-to-ac
Cost	$400,000

7. AC Battery

Contractor	Omnion Power Engineering
Utility	Pacific Gas and Electric
Primary application environment	Testing the concept of modular batteries in utility
Capacity	500 kW/500 kWh Converter interfaces the 250 V dc to 120 V ac.
Efficiency	To be determined

8. Tatsumi Energy Storage Test Facility [25]

Primary application	Load leveling This is a test facility supported by the New Energy and Industrial Technology Development Organization of the government of Japan.
Secondary application	Voltage and frequency regulation
Utility	Kansai Electric Power Co., Japan
Capacity	1 MW/4 MWh. Lead acid batteries rated at 1 MW for 4 h, sodium sulfur batteries rated at 1 MW for 8 h. Converter of 1 MW interfaces 1000 V dc to 6.6 kV ac.
Efficiency	71% lead-acid batteries ac-to-ac

9. BEWAG Battery Facility [19]

Primary application	Load frequency control and spinning reserve. This utility in former West Berlin supplies the load as an isolated utility. The lack of interconnections with neighboring systems makes the load frequency control an important concern. Utility Berliner Kraft and Licht AG, Berlin (BEWAG).
Capacity	8.5 MW (60 min)/17 MW (20 min) Two converters of 8.5 MW interface the 1180 dc and the 30 kV ac system.
Efficiency	Battery 85%, plant 80%

Compressed Energy Storage

Alabama Electric Cooperative (AEC) has just constructed a CAES plant to obtain load leveling benefits. The plant can store 2600 MWh of energy in the form of compressed air in a cavern of 19,000,000 ft^3 (530,020 m^3). It has a rating of 110 MW. For every kilowatt-hour of energy delivered, the plant requires an input of 0.82 kWh for air compression and 4122 Btu in the input natural gas to combustion turbines [10].

Studies of Battery Installation Benefits

Several studies have examined the economics of battery installation. The following is a brief listing of some major studies.

1. Cape Hatteras Storage Feasibility Studies

North Carolina Electric Membership Corporation and Cape Hatteras Electric Membership Corporation jointly studied the feasibility of a 2-MW/8-MWh battery installation for T&D deferral and voltage regulation benefits. The storage option was not found to be attractive when compared to the options of replacing some worn-out diesel engines.

2. Long Island Railroad (LIRR) Battery Energy Storage System

An internal study examined the possibility of battery storage to peak shave. LIRR has not reviewed the project after the completion of the study because of other priorities involving reorganization and service improvement.

3. Long Island Lighting Company (LILCO) Energy Storage

LILCO and its contractor (Bechtel National, Inc.) studied the economics of a 10-MW/50-MWh battery installation for load leveling. Because of poor economics of both utility substation and customer-side-of-the-meter applications, LILCO decided not to add the energy storage facility.

4. Princeton Plasma Physics Laboratory (PPPL) Battery Storage

PPPL studied the economics of a 5-MW battery installation for peak shaving and other benefits to the utility supplying PPPL's load. The economics of the project are being reevaluated based on the projected demand at PPPL.

5. Oglethorpe Battery Storage Facility

Oglethorpe Power Corporation (OPC) studied the installation of a 3-MW/9-MWh facility, primarily for load leveling. OPC is conducting further engineering analysis to identify many of the T&D benefits of battery storage. A decision on the project was expected in 1992.

6. Pacific Gas and Electric (PG&E) Company Battery Storage Project

PG&E studied a 10-MW/50-MWh storage project, primarily for load leveling. The conclusion of the study was to more accurately determine benefits and to find an optimized kWh/kW ratio for storage.

7. Berlin Subway Energy Storage Plant

Berlin Power and Light examined the economics of a 1-MW/3-MWh battery installation, primarily for peak shaving. The project is awaiting final negotiations regarding joint funding.

8. Southern California Edison (SCE) Project

SCE, through its research center, retained Power Technologies, Inc., to study all possible benefits of installing 10 Chino-type units (100 MW) of battery storage. After the completion of the first phase of study, a second phase is planned to identify the benefits more precisely, possibly for the 100 to 200 MW range of installations.

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Appendix 1

Capacity Credit

Electric utility resources are planned to deliver a certain reliability of service. Several methodologies and software packages exist that calculate reliability indices of networks, distribution systems, generating systems, and so forth.

Our focus is on resource or generation expansion. It is well known that generating units do break down and have to be maintained properly. The demand on the system is associated with some uncertainty. The uncertainty regarding the demand is greater for longer term projections than for shorter term projections. For example, the demand for the next day can be estimated fairly accurately with only about a 1% expected variation.

Resource expansion is generally based on an index of performance called the loss of load expectation (LOLE). This is computed by considering the probabilities of generating unit outages and the load variations to obtain a loss of load probability (LOLP). From the LOLP, LOLE is computed.

The above procedure is a simplistic explanation. There are several variations in the calculation of LOLE. An energy utility uses its own variant of the method, based on local conditions and judgment. For instance, some utilities calculate LOLP for the highest load in the year. This philosophy, called the worst case scenario, argues that if the highest load can be served with a certain level of reliability, then all other loads can be served with the same reliability or better. In another philosophy, LOLP is calculated for the 30 highest peak loads, the "worst" month. These LOLP are averaged before LOLE is computed. In yet another method, LOLP is calculated for all the hours in the worst month and averaged (the procedure of using the worst month load duration curve). Some utilities average the LOLP for all the hours during the year (the use of an annual load duration curve). In summary, it is important to note that although most utilities plan for the same or similar LOLE (such as 1 day in 10 years), the assumption and the planning criterion could be quite different. Therefore, by using the different methods espoused by the utilities on an illustrative system, one could obtain different generation reserves in the expansion scenarios.

Turning attention to RETs, consider the installation of PV generation in a utility whose planning philosophy is that of using the year's worst load, or the 30 worst loads of the year (worst month). Let the utility be winter peaking and the daily peak load occur in the evenings, around 6 p.m. Evidently, the PV generation obtains no capacity credit in such a situation. In other words, the required installation of capacity in the resource expansion plan will not be influenced one bit with the use of this reliability criterion.[1]

If we now use the same reliability criterion in a summer peaking system that has daily peaks occurring in the afternoon (as in some West Coast utilities with large air conditioning loads), the PV installation gets full capacity credit (somewhat modified by the probability of losing insolation during the day). In other words, this utility can avoid the installation of conventional capacity equal to that of the PV in its resource expansion plan.

If the same utility were to use a criterion for reliability that considered, say, all the hourly loads in the worst month, the capacity credit for the PV would be less. This arises from the fact that PV output does

[1]It is not our intent to criticize this index. One might justify this index of performance for several reasons. Our intent is to debate how the indices of performance impinge on capacity credit.

not occur during all hours. Hence, it does not contribute power during all the hours during which reliability is computed. Consequently, its contribution will be less than the previously suggested reliability criterion.

The previous examples are extremes. They stress the point, however, that the capacity credit depends on the correlation between the RET output and system demand, and the reliability criterion used by the utility.

In terms of wind installations, it is well known that utilities are reluctant to give such installations any capacity credit. The reluctance arises from the following considerations.

Section 3 of the report discusses the unit commitment process briefly. As indicated, the utility plans the starting and stopping of units a week ahead of the forecast load. When such a plan is refined each day with specific instructions for the following day, as to which unit should be brought on-line, the utility needs and has a knowledge of the status of units. This information consists of which machines are on forced outage, which ones are on maintenance, which fuels are available and in what quantities, etc. Another consideration is that of shorter term predictability.[2] If a generating unit is operating well with no noted complaints today, there is a very good possibility that it will be running tomorrow.

The same cannot be said of the short-term predictability of wind. Even though the wind machines might be producing today, there is no assurance that they will be producing energy tomorrow.[3] As a result, in the unit-commitment plans for the next day, one cannot be certain about the availability of wind energy. Therefore, although energy from wind can be absorbed as and when available, one cannot avoid committing any capacity to meet the load. It is argued, therefore, that wind generation can only obtain a very small capacity credit.[4]

The capacity credit given to wind and PV generation is related to the probability that the resource will be available at the time of system peaks. The computation of this probability requires large amounts of resource data over the past several years. In theory, if the data were to be available over a wide geographical area, one could compute the mathematical expectations of generation availability at the time of system peak demand from a dispersed installation of such generation. To our knowledge, such computations have not yet been made.

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[2]A probability measure can be associated with this possibility.

[3]This points to the need for short-term prediction models for RETs to indicate if there will be output from such installations with a certain degree of confidence.

[4]In some locations, such as at Solano in California, one might find predictability in the wind pattern and correlation with system demand. Under such conditions of increased predictability, wind generation does indeed get more capacity credit than in locations with a high degree of variability.

Appendix 2

Optimization Study (kW-kWh) of an Illustrative Utility for Load Leveling

The following details are for an illustrative utility.

The generation mix was assumed to be identical to that of the IEEE Committee report, "IEEE Reliability Test System" [1], as shown in Table 2-1.

Table 2-1. Generation Mix of the Illustrative Utility

Fuel	No. of Units	Size (MW)	FOR	λ$/MWh
Fossil-steam	5	12	0.02	28.558
Combustion turbine	4	20	0.10	37.5
Hydro	6	50	0.01	0
Coal-steam	4	76	0.02	14.882
Oil-steam	3	100	0.04	22.08
Coal-steam	4	155	0.04	11.16
Oil-steam	3	197	0.05	19.87
Coal-steam	1	350	0.08	11.4
Nuclear	2	400	0.12	5.592
Total		3405		

Although the computer program was capable of accepting annual hourly loads or the load duration curve, the daily hourly load, shown in Table 2-2 was assumed to repeat for 250 days to calculate storage benefits.

Description of Computer Program

The program computes the hourly demand from the above footnote data.[5] The avoided cost-benefits and pumping costs can be calculated if the cost curve f(L,λ) of Figure 2-1, and the hourly discharging and charging capacity are known.

The cost curve was computed by a separate computer program at NREL. The relation between load and expected λ is computed by the program. Therefore, this implies that the possibilities of forced outage of the generators have already been considered in computing this relation. A polynomial fit to this relation was found to be

$$\lambda = 10.791 - 0.003251\ L + 0.39681\ 10^{-5}\ L^2 \qquad (2\text{-}1)$$

where L is in megawatts.

The next computation is that of hourly charging and discharging loads. The user inputs values of energy and capacity for the storage device that the program is to consider.

[5]The program can also perform calculations using the parameters of the load duration curve instead of hourly loads.

Table 2-2. Hourly Loads Used in Study (percent of daily peak)

Hour	midnight-1 a.m.	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12 noon
Eve. peak case	67	63	60	59	59	60	74	86	95	96	96	95
Day peak case	41	42	45	53	59	65	73	80	88	90	95	99
Hour	noon - 1 p.m.	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-midnight
Eve. peak case	95	95	93	94	99	100	100	96	91	83	73	63
Day peak case	100	100	98	86	80	81	85	80	75	65	55	42

Figure 2-2, taken from *Economics of Energy Storage Devices in Interconnected Systems—A New Approach* [2], illustrates the operating strategy.

In the discharge mode, PUYEZXT will be the load profile during the discharge hours. One operating strategy would be to start discharging at time t_2 at the full rated capacity. The net system load decreases to V. The storage is discharged until time t_5 such that the area within UVQRSWXZEY is equal to the specified energy. Note in this mode of operation that there is no smooth transition of load during the period t_1 to t_3, and that the load U at t_2 is higher than some traditionally peak hours, say at t_3.

The other mode of operation is to start discharging at t_1. The capacity of discharge is gradually increased from zero at t_1 to its full capacity at t_3. The discharge period is from t_1 to t_6, and the area bounded by PQRSTXZEYU is also equal to the specified energy.

It is shown in reference 2 that the latter strategy results in more benefits than the former, unless the load-marginal cost relation is constant. The gradual increase in discharge capacity during the period t_1 to t_3 can be achieved by operating the storage in a LFC mode.

In actual operating practice, the operator does not know the time t at which the storage has to start discharging. He does not have exact knowledge of the load to occur during the future interval t_1 to t_6. Therefore, the latter discharge strategy gives the theoretical maximum benefits possible.

The computer program calculates the net load of the latter strategy. This computation uses the principle that there should be no jump discontinuities in the demand from hour to hour. In addition, the difference between the load without the operation of storage (PUYZXT) and with the operation of storage (PQRST) should be proportional to the system load over and above the value at t_1, subject to a maximum of storage capacity.

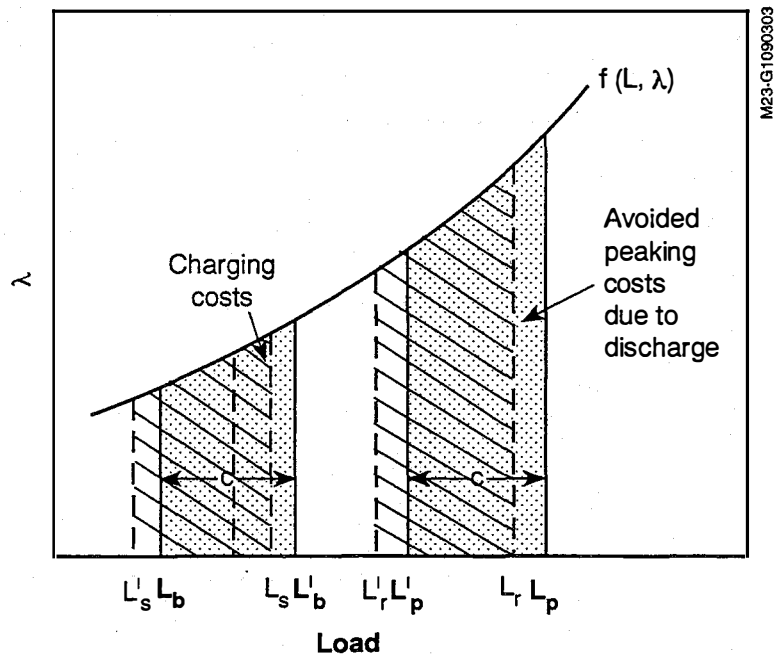
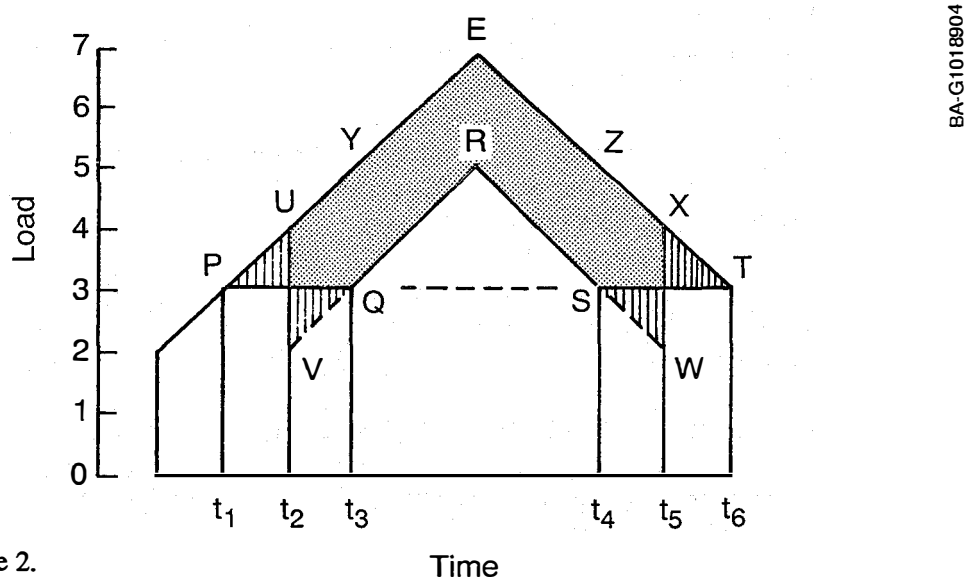


Figure 2-1. Charging costs and discharging benefits



Source: Reference 2.

Figure 2-2. Illustration of two discharging strategies

Having computed the charging and discharging loads by the previous procedure, the benefit is calculated by integrating equation 2-1 between appropriate limits.

Renewable Energy Technology

The program permits the input of any temporal profile for generation from RETs. In our study, the temporal profiles shown in Table 2-3 were assumed. The generation in each hour is expressed as a percentage of the maximum.

Table 2-3. Temporal Profiles Used in Study

Hour	mid-night-1 a.m.	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12 noon
PV	0	0	0	0	0	0	0	10	20	35	57	75
Wind	10	0	0	0	10	10	10	10	20	25	30	35
Hour	noon-1 p.m.	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-mid-night
PV	90	100	90	68	45	15	0.5	0	0	0	0	0
Wind	36	40	45	60	65	85	95	100	90	70	40	20

Cost of Storage Equipment

Some representative costs of storage technologies have been given in Section 3 of the report. For example, the cost of battery installation is $300,000 + $260/kW + $76/kWh for light-duty batteries. The user inputs the cost of capital into the program. Assuming that the installation lasts (and is amortized over that period) for 30 years, and that the battery life is only 5 years, the annual payments for the first two components of the cost for a given capacity and energy are easily obtained. The annual payments for 5 years' life of the last component also is obtained. The sum of the two annual payments is the total cost shown as the results of our study in Tables 2-4 to 2-8.

Note

Observe that the cost relationship of equation 2-1 is relatively flat. With the costs of batteries, as suggested previously, and with costs of any storage technology, as suggested in this report, it was found that *there would be no load leveling benefit for any capacity or energy combination of storage.* Obviously, the computer program selects zero capacity and energy as the optimum ratings of storage.

To make our point regarding the effect of RETs on storage capacity, we assumed some hypothetical values that would make storage economical. They were as follows:

Cost of storage:

This was assumed to be

$$\$300{,}000 + \$50/\text{kW} + \$15/\text{kWh}$$

Load-incremental cost relation:

This was assumed to be

$$\lambda = 0.001 \text{ Exp } (1.98 \text{ L})$$

where L is in MW.

Results

Table 2-4 shows the values for an assumed temporal load profile that has a peak at 6 p.m. (termed the evening peak case). Table 2-5 shows the same results for a load profile having a peak at 2 p.m. (termed the day peak case). The latter case represents regions with predominant air conditioning demands. In these tables, no IRET installations have been assumed.

In Tables 2-4 and 2-5, the avoided cost due to the displacement of peaking generation, the charging costs, and the benefits given by the difference between these two costs are shown for different megawatt and megawatt-hour storage capacities. All the cost figures are annual costs. The combinations of excess storage capacity or energy are identified by the computer algorithm. An excess energy situation arises when the required energy cannot be stored using storage capacity and off-peak energy. An excess capacity situation arises when a smooth variation of load from one hour to another is not possible. The entries in the not- permissible range are left blank in the tables. Note that the benefits in the allowable range increase with the increase in capacity and energy.

The benefits tell only part of the story. The annual cost of storage also increases with storage capacity and energy rating. Therefore, the net annual benefits given by the difference between the benefits and costs are of significance.[6] The difference between the benefits and costs is also shown in these tables. The maximum value of this difference (which is highlighted in boldface) is the optimum.

The tables contain much information obtained from the algorithm. It is necessary to understand the entries clearly to assess the effect of RETs on storage. The following discussion of the tables is intended to facilitate the entries.

Figures 2-3 and 2-4 illustrate the results of Table 2-5. Figure 2-3 shows the avoided costs due to discharges during the peak-load period and shows the charging costs. Note that the avoided costs, as well as the charging costs, increase with increasing energy. The difference between these two costs is the net benefit, shown in Figure 2-4. The net benefits increase with increasing energy, but a larger capacity is required to realize the increased benefits.

The cost of the storage installation also increases with its capacity and energy. Therefore, although net benefits increase with increasing capacity and energy of the storage system, from a planning perspective, the difference between the costs and benefits determines the optimal installation. It can be seen that the optimum in the evening peak case (Table 2-4) is at 100 MW and 500 MWh (cost minus benefit of $1.53 E05). The corresponding optimum for the day peak case is at 225 MW and 1000 MWh, for a benefit of $1.14 E06. The optimum is a function of the load—marginal-cost relationship and the load shape. Consequently, the megawatt and megawatt-hour optimum for storage could be different for different systems.

[6]As pointed out therein, an unrealistically low cost for storage has been assumed to illustrate our point.

Table 2-4. Annual Benefits (in Dollars) Due to Load Leveling—No RET Installation, Evening Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost	1.80E+07					
	Charging Cost	1.16E+07					
	Benefit	6.39E+06					
	Annual Cost	9.51E+06					
	Benefit – Cost	-3.12E+06					
225	Avoided Cost		1.46E+07	1.27E+07			
	Charging Cost		8.87E+06	7.01E+06			
	Benefit		5.77E+06	5.71E+06			
	Annual Cost		7.60E+06	6.65E+06			
	Benefit – Cost		-1.82E+06	-9.49E+05			
125	Avoided Cost				8.66E+06	4.55E+06	
	Charging Cost				4.92E+06	1.99E+06	
	Benefit				3.74E+06	2.55E+06	
	Annual Cost				4.33E+06	2.46E+06	
	Benefit – Cost				-5.95E+05	9.66E+04	
100	Avoided Cost				8.60E+06	4.52E+06	
	Charging Cost				5.76E+06	2.02E+06	
	Benefit				2.84E+06	***2.50E+06***	
	Annual Cost				4.22E+06	2.35E+06	
	Benefit – Cost				-1.38E+06	**1.53E+05**	
75	Avoided Cost					4.47E+06	2.35E+06
	Charging Cost					2.17E+06	9.60E+06
	Benefit					2.30E+06	1.39E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit – Cost					6.33E+04	9.43E+04
40	Avoided Cost						2.28E+06
	Charging Cost						1.04E+06
	Benefit						1.23E+06
	Annual Cost						1.14E+06
	Benefit – Cost						9.17E+04

Table 2-5. Annual Benefits (in Dollars) Due to Load Leveling—No RET Installation, Day Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost	1.65E+07	1.38E+07	1.22E+07			
	Charging Cost	8.24E+06	5.70E+06	4.54E+06			
	Benefit	8.23E+06	8.17E+06	7.74E+06			
	Annual Cost	9.51E+06	7.82E+06	6.88E+06			
	Benefit – Cost	-1.27E+06	3.50E+05	8.56E+05			
225	Avoided Cost		1.35E+07	1.20E+07	8.65E+06		
	Charging Cost		6.29E+06	4.89E+06	2.73E+06		
	Benefit		7.23E+06	7.13E+06	***5.92E+06***		
	Annual Cost		7.60E+06	6.66E+06	4.78E+06		
	Benefit – Cost		-3.66E+05	4.74E+05	**1.14E+06**		
125	Avoided Cost				8.03E+06	4.57E+06	
	Charging Cost				3.50E+06	1.25E+06	
	Benefit				4.53E+06	3.31E+06	
	Annual Cost				4.33E+06	2.46E+06	
	Benefit – Cost				1.79E+05	8.54E+05	
100	Avoided Cost					4.51E+06	
	Charging Cost					1.34E+06	
	Benefit					3.17E+06	
	Annual Cost					2.34E+06	
	Benefit – Cost					8.26E+05	
75	Avoided Cost					4.29E+06	2.36E+06
	Charging cost					1.52E+06	5.78E+05
	Benefit					2.77E+06	1.78E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit – Cost					5.39E+05	4.88E+05
40	Avoided Cost						2.21E+06
	Charging Cost						7.24E+05
	Benefit						1.49E+06
	Annual Cost						1.14E+06
	Benefit – Cost						3.50E+05

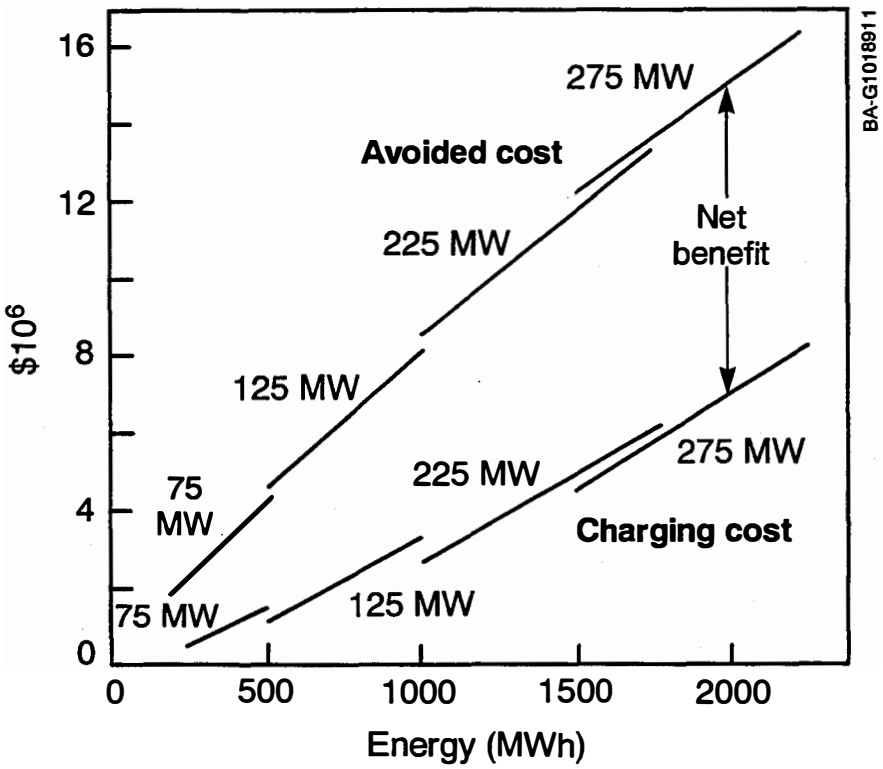


Figure 2-3. Avoided and charging costs

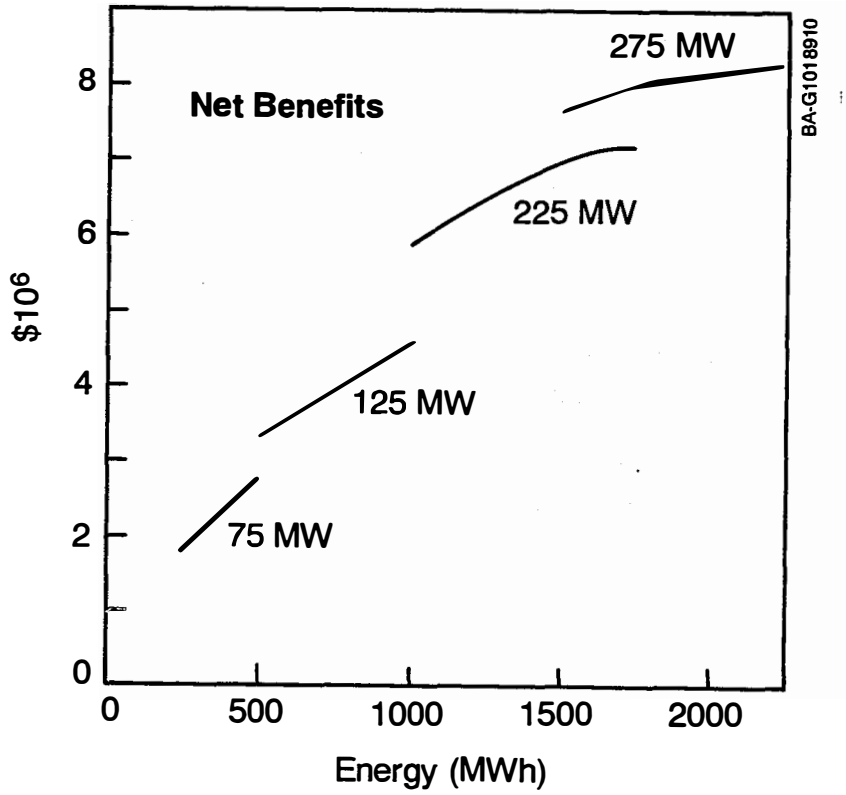


Figure 2-4. Net benefits

Effect of RET Penetration

We now examine the effect of installing 100 MW of wind generation (about 3% of peak load) and 300 MW of PV generation in the day peaking and evening peaking systems. Tables 2-6 and 2-7 show the results for the penetration of these technologies in the evening peaking system and Tables 2-8 and 2-9 show the corresponding results for the day peaking system. Our object is to examine the effect of RETs on the planning and operation of the system.

Planning Considerations

The first scenario is that the systems under investigation do not already have installed storage. The object is to compare the amount of optimal storage when the resource expansion plan includes a RET with that of a plan that does not include a RET. A comparison of Tables 2-6 and 2-7 with Table 2-4 permits this. Note that in Tables 2-6 and 2-7 benefits minus costs from storage are negative when a RET is installed, either with the wind or PV penetration. This arises from the fact that the penetration of RETs reduces the difference between the peak load and base load for the assumed resource profile. That is, RETs "flatten" the load.[7] Consequently, the production cost of energy in the system decreases.

For the day peak case, note from Table 2-8 that the optimal storage is at 225 MW and 1000 MWh for 100 MW of wind penetration. The gain (benefit-cost), however, is $8.46 E05, which is slightly less than the case without a RET in Table 2-5. Observe from comparing charging costs in Table 2-8 with those of Table 2-5 that the assumed profile of wind energy during off-peak hours reduces the charging costs.

For the case of PV generation in the day peak case, note that there are no advantages from the load leveling operation of storage as revealed in Table 2-9; that is, all cost minus benefit figures are negative.

Therefore, from a planning perspective, except for the 100-MW wind installation in the day peak case, one would not choose storage installation.

The above discussion indicates that it is not possible to generalize conclusions regarding the optimum storage capacity. The optimum value depends on the load profile, vis-à-vis the output of RETs, and system marginal costs. In terms of the effect of RETs on the benefits, the results in the tables can be used to make some general but vital observations.

There is a reduction of charging costs due to the injection of RET energy during charging (off-peak) periods. The actual short-run marginal cost of the RET energy is almost zero. Consequently, since the generation from conventional sources decreases when there is a penetration of RET energy, the system marginal cost decreases. Therefore, if there is an injection of energy during peak-load hours, the system marginal costs decrease, resulting in a reduction of avoided cost due to the discharge of stored energy (see Figure 2-1). Note that in the tables depicting RET penetration, the avoided costs have decreased because of this phenomenon.

The difference between avoided cost and charging cost represents benefits due to storage. Therefore, the question is, which of these two components decreases more? Evidently, for the same amount of energy injected during on-peak and off-peak periods, the reduction in avoided cost will be larger than the charging cost reduction because of the increasing nature (convexity) of the load–marginal cost relationship (Figure 2-1). As a result, *any injection of RET energy, unless it is only during the off-peak period,*

[7]Such a flattening will not occur if the output of a RET is only during off-peak hours. In such a pathological case, the difference between peak load and low loads would increase.

reduces the benefits due to load leveling operation of storage. This is borne out in the results of the study. For example, for the day peak case in Table 2-8, the benefits have decreased to $5.62 E06 from $5.92 E06 in Table 2-5.

The value of the RET energy is also shown in the tables. For example, the value of wind energy for the assumed profile in the day peak case is $5.29 E06 per year. This is not an imputed value. This represents the mathematical expectation of the savings in production cost due to wind energy integration.

Operational Considerations

The second scenario is that the systems have already installed optimum storage. Then the effect of installing RET energy on changes in operational economics is a concern.

In operational matters, given that a certain megawatt and megawatt-hour storage capability has already been installed, the object is to maximize the benefits given by the difference between avoided peaking costs and charging costs. The concern is *not* to maximize the difference between benefits minus the capital costs of storage, as in planning exercises.[8]

Therefore, our objective is to compare the benefits without IRETs in the systems of Tables 2-4 and 2-5 with the benefits with IRETs in Tables 2-8 to 2-9.

For the evening peak case, assume that a storage capacity of 100 MW and 500 MWh is already installed in the system, which permits maximum benefits of $2.50 E06 per year without IRETs, as shown in Table 2-4. A wind installation of 100 MW would permit the realization of $2.23 E06 as benefits of operating the existing storage (see Table 2-6). This reduction of benefits should be taken into account in the cost-benefit analysis of the installation of wind generation. Similarly, the injection of 300 MW of PV generation also reduces the benefits to $2.24 E06, as shown in Table 2-7.

For the day peak case, we obtain similar results. The benefits without IRETs by operating a 225 MW, 1000-MWh storage are $5.92 E06 per year. Infusion of 100 MW of wind reduces this to $5.62 E06.

Discussion of Results

These results are not surprising and are intuitively obvious. In any system, the reduction of the difference between the peak and off-peak loads decreases the benefits due to load leveling. Such is the case with DSM measures as in valley filling, strategic marketing, and heat and cold storage. Then, of what particular significance are these results to IRETs?

In spite of its attraction, the point of concern about IRETs is intermittence and cost competitiveness with conventional technologies. Unlike DSM programs that can be controlled,[9] the output of IRETs has to be absorbed into the system when available. The installation of energy storage to mitigate the effect of intermittence, called reliability-related storage, increases costs and puts it at a cost disadvantage in comparison with conventional alternatives. Therefore, can the IRET generation, in spite of its intermittence, be absorbed into a system by a proper rearrangement of existing storage operation? How does existing storage impinge on the operation of IRETs and vice versa?

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[8]Further, it is also possible that the capital outlay has been either partially or fully amortized.

[9]Only programs that result in a suitable load characteristic will be supported by a utility and its regulators. In many instances, load control permits the dispatching of DSM measures by the central operator to maximize benefits. The generation of IRETs is not controllable by the operator.

Table 2-6. Annual Benefits (in Dollars) Due to Load Leveling—100-MW Wind Generation, Evening Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost						
	Charging Cost						
	Benefit						
	Annual Cost						
	Benefit – Cost						
225	Avoided Cost		1.38E+07				
	Charging Cost		8.71E+06				
	Benefit		5.11E+06				
	Annual Cost		7.60E+06				
	Benefit – Cost		-2.48E+06				
125	Avoided Cost				8.19E+06		
	Charging Cost				4.82E+06		
	Benefit				3.36E+06		
	Annual Cost				4.33E+06		
	Benefit – Cost				-9.69E+05		
100	Avoided Cost				8.14E+06	4.24E+06	
	Charging Cost				5.59E+06	2.01E+06	
	Benefit				2.55E+06	***2.23E+06***	
	Annual Cost				4.22E+06	2.34E+06	
	Benefit – Cost				-1.60E+06	-1.13E+05	
75	Avoided Cost					4.22E+06	2.18E+06
	Charging Cost					2.15E+06	9.54E+06
	Benefit					2.07E+06	1.22E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit - Cost					-1.61E+05	-7.38E+04
40	Avoided Cost						2.15E+06
	Charging Cost						1.03E+06
	Benefit						1.18E+06
	Annual Cost						1.14E+06
	Benefit – Cost						2.49E+04

Table 2-7. Annual Benefits (in Dollars) Due to Load Leveling—300-MW PV Installation, Evening Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost		1.34E+07	1.88E+07			
	Charging Cost		8.23E+06	6.73E+06			
	Benefit		5.25E+06	5.07E+06			
	Annual Cost		7.82E+06	6.88E+06			
	Benefit – Cost		-2.56E+06	-1.81E+06			
225	Avoided Cost			1.17E+07	8.21E+06		
	Charging Cost			7.01E+06	4.22E+06		
	Benefit			4.71E+06	3.99E+06		
	Annual Cost			6.66E+06	4.78E+06		
	Benefit – Cost			-1.94E+06	-7.91E+06		
125	Avoided Cost				7.95E+06	4.32E+06	
	Charging Cost				4.91E+06	1.99E+06	
	Benefit				3.04E+06	2.33E+06	
	Annual Cost				4.33E+06	2.46E+06	
	Benefit – Cost				-1.29E+06	-1.30E+05	
100	Avoided Cost					4.27E+06	
	Charging Cost					2.02E+06	
	Benefit					***2.24E+06***	
	Annual Cost					2.34E+06	
	Benefit – Cost					-1.01E+05	
75	Avoided Cost					4.17E+06	2.24E+06
	Charging Cost					2.17E+06	9.60E+05
	Benefit					2.00E+06	1.28E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit – Cost					-2.36E+05	-9.17E+03
40	Avoided Cost						2.14E+06
	Charging Cost						1.04E+06
	Benefit						1.95E+06
	Annual Cost						1.14E+06
	Benefit – Cost						-4.83E+04

Table 2-8. Annual Benefits (in Dollars) Due to Load Leveling—100-MW Wind Generation, Day Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost	1.58E+07	1.30E+07	1.18E+07			
	Charging Cost	8.07E+06	5.60E+06	4.48E+06			
	Benefit	7.80E+06	7.70E+06	7.36E+06			
	Annual Cost	9.51E+06	7.82E+06	6.88E+06			
	Benefit – Cost	-1.69E+06	-4.17E+04	4.79E+05			
225	Avoided Cost		1.30E+07	1.16E+07	8.33E+06		
	Charging Cost		6.14E+06	4.80E+06	2.70E+06		
	Benefit		6.88E+06	6.80E+06	***5.62E+06***		
	Annual Cost		7.60E+06	6.66E+06	4.78E+06		
	Benefit – Cost		-7.18E+05	1.43E+05	**8.46E+05**		
125	Avoided Cost				7.74E+06	4.39E+06	
	Charging Cost				3.41E+06	1.24E+06	
	Benefit				4.32E+06	3.15E+06	
	Annual Cost				4.33E+06	2.46E+06	
	Benefit – Cost				-1.33E+04	6.92E+05	
100	Avoided Cost				7.87E+06	4.34E+06	
	Charging Cost				5.80E+06	1.32E+06	
	Benefit				2.07E+06	3.02E+06	
	Annual Cost				4.22E+06	2.34E+06	
	Benefit – Cost				-2.14E+06	6.76E+05	
75	Avoided Cost					4.15E+06	2.27E+06
	Charging Cost					1.49E+06	5.75E+05
	Benefit					2.66E+06	1.70E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit – Cost					4.24E+05	4.02E+05
40	Avoided Cost						2.14E+06
	Charging Cost						7.10E+05
	Benefit						1.43E+06
	Annual Cost						1.14E+06
	Benefit – Cost						2.87E+05

Table 2-9. Annual Benefits (in Dollars) Due to Load Leveling—300-MW PV Generation, Day Peak

Capacity (MW)	Benefits/Costs	Energy (MWh) 2200	1750	1500	1000	500	250
275	Avoided Cost	1.36E+07	1.12E+07	9.77E+06			
	Charging Cost	8.26E+06	5.70E+06	4.54E+06			
	Benefit	5.36E+06	5.49E+06	5.22E+06			
	Annual Cost	9.51E+06	7.82E+06	6.88E+06			
	Benefit – Cost	-4.15E+06	-2.32E+06	-1.65E+06			
225	Avoided Cost		1.13E+07	9.75E+06			
	Charging Cost		6.29E+06	4.89E+06			
	Benefit		4.83E+06	4.85E+06			
	Annual Cost		7.60E+06	6.66E+06			
	Benefit – Cost		-2.76E+06	-1.80E+06			
125	Avoided Cost				6.64E+06	3.53E+06	
	Charging Cost				3.50E+06	1.25E+06	
	Benefit				3.13E+06	2.27E+06	
	Annual Cost				4.33E+06	2.46E+06	
	Benefit – Cost				-1.19E+06	-1.82E+05	
100	Avoided Cost					5.20E+06	
	Charging Cost					1.34E+06	
	Benefit					3.86E+06	
	Annual Cost					2.34E+06	
	Benefit – Cost					-1.51E+06	
75	Avoided Cost					3.47E+06	1.81E+06
	Charging Cost					1.52E+06	5.78E+06
	Benefit					1.92E+06	1.24E+06
	Annual Cost					2.23E+06	1.29E+06
	Benefit – Cost					-2.85E+05	-5.88E+04
40	Avoided Cost						1.77E+06
	Charging Cost						7.24E+05
	Benefit						1.05E+06
	Annual Cost						1.14E+06
	Benefit – Cost						-9.07E+06

The answer would depend on a detailed analysis of storage in different dispatch strategies. Presumably, storage can be dispatched in different modes during different times of the day/year. Understandably, load leveling is one mode of operation. The benefits from storage can be maximized by an optimal mix of dispatch strategies. If the benefits from load leveling decrease because of the penetration of IRETs or other technologies, the dispatch strategy has to be shifted to other modes of operation. The question concerns the total benefits in other modes of operation. Will they decrease because of the penetration of these new technologies? The answer, without a system-specific detailed analysis, is unclear. It is necessary to examine the effect of IRET benefits in other modes of storage dispatch before any general conclusions can be made. For instance, existing storage can be used to absorb the energy from intermittent sources and redispatched at some other time of the day. If there is hydroelectric generation in a system, its generation can be held back by reducing the water release when the intermittent sources are generating. The energy held back in the reservoir can be generated at some other time of the day. Such an operation allows the utility to match the energy obtained by the intermittent source to the demand pattern, referred to as "firming up" the intermittent generation.

The scope of this work did not encompass a study of such other modes of dispatch.

Summary

In essence, we have shown that the penetration of IRET generation changes the temporal shape of net demand. Therefore, any load leveling benefit due to already existing storage will be reduced. However, existing storage can be dispatched in other modes to maximize benefits. An example of such a reorientation is that of altering the operation of existing storage to be used as a backup to mitigate the intermittency of IRETs. In resource expansion plans, these effects on the economics of operation have to be properly accounted for.

References

1. IEEE Committee. "IEEE Reliability Test System," *IEEE Transactions on PAS*, Vol. 101, No. 8, pp. 2649-2655, 1982.

2. Rau, N.S. and Necsulescu, C. "Economics of Energy Storage Devices in Interconnected Systems—A New Approach," *IEEE Transactions on Power Apparatus and Systems*, pp. 1217-1233, June 1984.

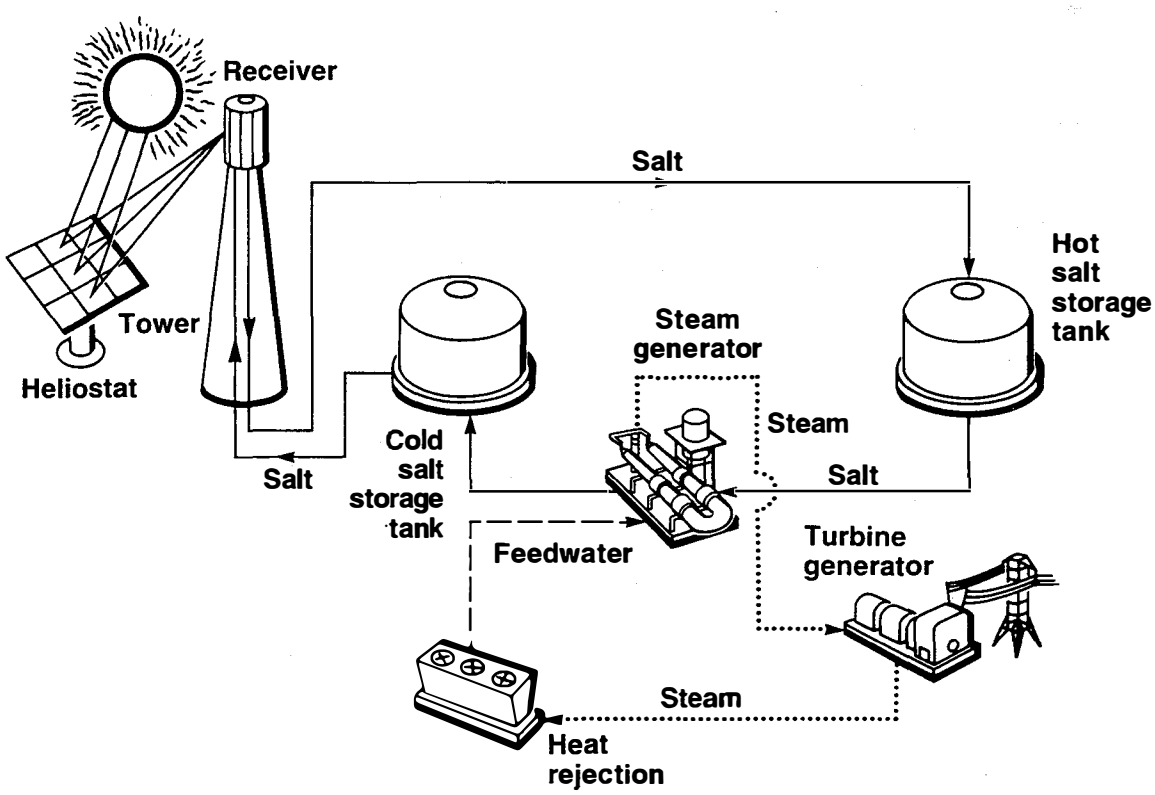
Appendix 3

Nonelectrical Forms of Storage—Thermal Energy Storage

Solar Central Receiver Systems

In contrast to electrical energy storage, thermal energy storage offers some distinct advantages for central solar thermal generation. In the central receiver system, at the site of generation, solar energy is reflected from a set of mirrors to a central receiver, as shown in Figure 3-1. In the central receiver, solar thermal energy is used to heat and keep nitrate salts in a molten condition. A heat exchanger (steam generator) extracts the sensible heat in the salt to generate steam. Electricity is generated in a conventional cycle using steam.

The concept of the design is to make the rate of electricity generation less than the rate of solar energy input during certain times of the day. Figure 3-2 shows the operating strategy. In this mode of operation, some heat is stored in the salt as sensible heat and is depleted during nonsunshine hours. As a result of such design, even though the sun shines for a few hours during the day, the output from the plant can be stretched over a longer period.



Source: *Today's Solar Power Towers*, Sandia National Laboratories, December 1991 [Reference 1].

Figure 3-1. Schematic of electricity generation using molten-salt technology in a central receiver system

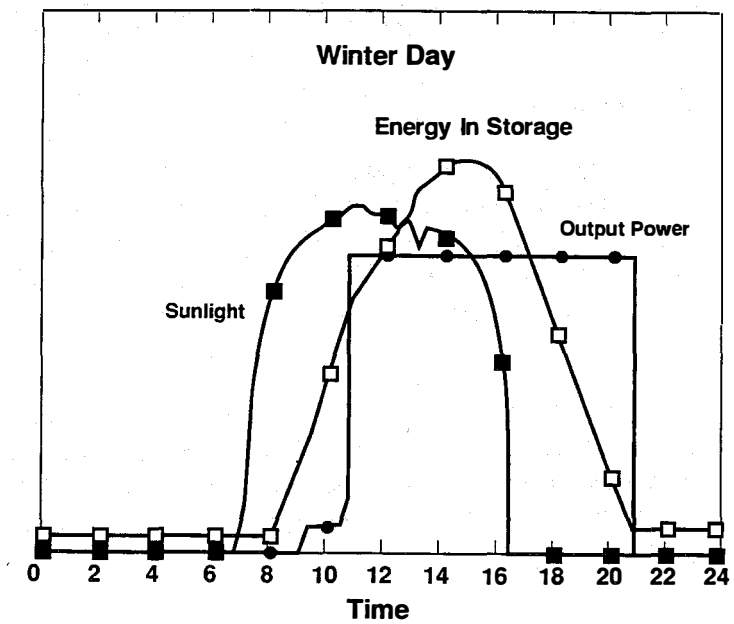


Figure 3-2. Load dispatching capability of central receiver plants

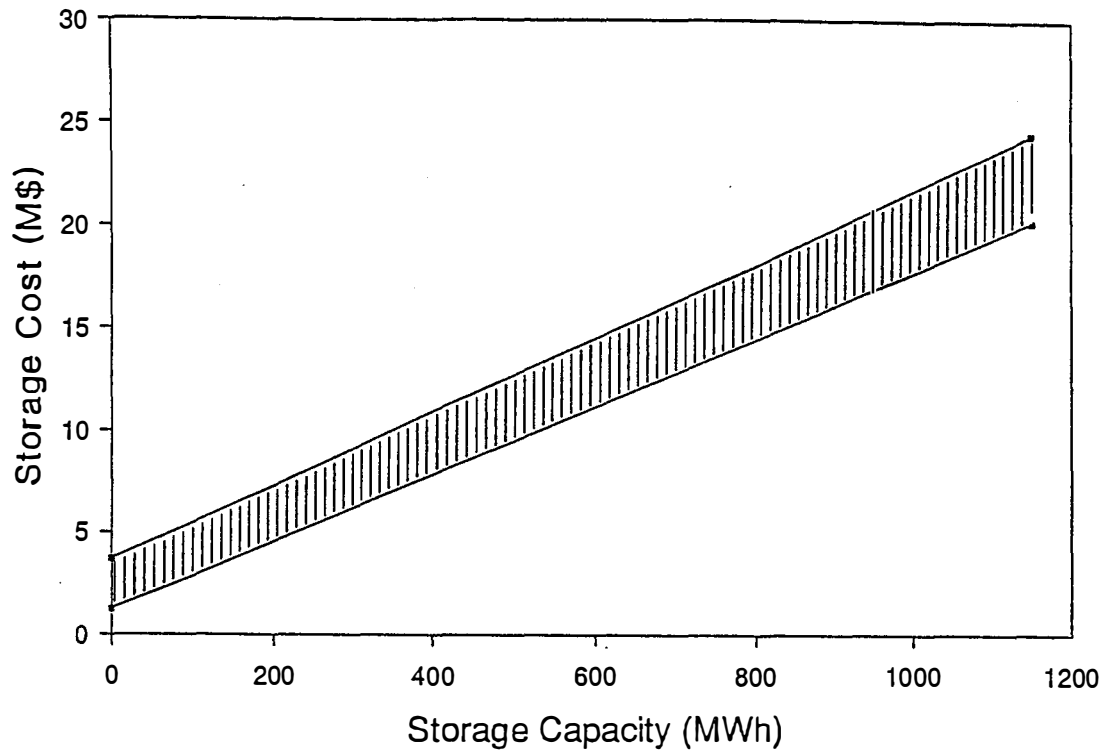
Regarding the cost associated with heat storage in central receiver systems, *A Handbook for Solar Central Receiver Design* [2] states:

> The cost of thermal storage is broken into power-related (charging and discharging) and capacity-related groups and correlated with thermal power rating (MW_t) and capacity (MWh), respectively. Capacity-related costs dominate thermal energy storage systems, however, and cost correlations based on megawatt-hours alone predict costs well for the entire storage system....

Figure 3-3 indicates the cost associated with this mode of heat storage related to megawatt-hours. This cost is small in comparison with the total cost of the plant itself, which is several orders of magnitude higher. Consequently, its influence on the overall cost (cents per kilowatt-hour) is very small. Further details regarding cost can be found in reference 2.

End-Use Thermal Energy Storage

One demand-side management initiative is to store thermal energy on the premises of the end user. An example is the storage of heat in water, concrete blocks, or molten salts in homes. The heat input to these devices comes either from solar panels on the consumer's home or from the utility supply at low load periods. Extraction of heat during peak load periods results in savings because of the improved load factor of distribution feeders.



Source: *A Handbook for Solar Central Receiver Design*, Sandia National Laboratories, December 1986 [2].

Figure 3-3. Thermal storage system cost as a function of storage capacity

Another example of industrial heat storage is the modification of chillers approved by the New Jersey Board of Public Utilities [3]. Under this program,[10] the user installed eutectic salts in five treatment groups using chillers. During off-peak periods, the existing chiller equipment in the ice-making plant will be used to charge the storage tank. During peak period, the stored cooling capacity will be discharged and used to cool the facility. A reduction in demand of 12,285 kW is anticipated in 1992.

The economics of end-use thermal storage schemes appear to be project specific. Therefore, it would be improper to suggest global cost figures.

Effect of Storage on RET Penetration and the Effect of RETs on System Operation

As discussed earlier, the presence of storage influences the selection of RETs in resource expansion plans. In order to understand such a relationship, it is necessary to discuss the details of operation of storage in the load leveling mode. The operational details of load leveling were simulated in a study conducted on an illustrative and somewhat hypothetical system.

[10]This example has no bearing on IRETs. However, it illustrates that the end user could use heat or cold storage derived from on-location solar panels or wind generation to reduce the demand on the utility's system.

References

1. *Today's Solar Power Towers.* Sandia National Laboratories, December 1991.

2. Falcone, P.K. *A Handbook for Solar Central Receiver Design,* Sandia National Laboratories, SAND 86-8009, December 1986.

3. New Jersey Board of Public Utilities. "In the matter of the application for approval of the power savings agreement between Transphase System, Inc., and Jersey Central Power and Light Co.," Order of Approval, Docket No. 8010-687b, September 1988.

REPORT DOCUMENTATION PAGE

Form Approved
OMB NO. 0704-0188

Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.

1. AGENCY USE ONLY (Leave blank)

2. REPORT DATE.
August 1994

3. REPORT TYPE AND DATES COVERED
Technical report

4. TITLE AND SUBTITLE
The State of Energy Storage in Electric Utility Systems and Its Effect on Renewable Energy Resources

5. FUNDING NUMBERS
AS815440
AS819205

6. AUTHOR(S)
Narayan S. Rau

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, CO 80401-3393

8. PERFORMING ORGANIZATION REPORT NUMBER
TP-462-5337

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

10. SPONSORING/MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES

12a. DISTRIBUTION/AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

12b. DISTRIBUTION CODE
UC 1371

13. ABSTRACT *(Maximum 200 words)*

This report describes the state of the art of electric energy storage technologies and discusses how adding intermittent renewable energy technologies (IRETs) to a utility network affects the benefits from storage dispatch. Load leveling was the mode of storage dispatch examined in the study. However, the report recommended that other modes be examined in the future for kilowatt and kilowatt-hour optimization of storage. The motivation to install storage with IRET generation can arise from two considerations: reliability and enhancement of the value of energy. Because adding storage increases cost, reliability-related storage is attractive only if the accruing benefits exceed the cost of storage installation. The study revealed that the operation of storage should not be guided by the output of the IRET but rather by system marginal costs. Consequently, in planning studies to quantify benefits, storage should be considered as an entity belonging to the system and not as a component of IRETs. The study also indicated that because the infusion of IRET energy tends to reduce system marginal cost, the benefits from load leveling (value of energy) would be reduced. However, if a system has storage, particularly if the storage is underutilized, its dispatch can be reoriented to enhance the benefits of IRET integration.

14. SUBJECT TERMS
energy storage; intermittent renewable energy; renewable resources; electric utility systems

15. NUMBER OF PAGES
64

16. PRICE CODE
A06

17. SECURITY CLASSIFICATION OF REPORT
unclassified

18. SECURITY CLASSIFICATION OF THIS PAGE
unclassified

19. SECURITY CLASSIFICATION OF ABSTRACT
unclassified

20. LIMITATION OF ABSTRACT
UL