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Modeling of Battery Energy Storage in the National Energy Modeling System

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Abstract

The National Energy Modeling System (NEMS) developed by the U.S. Department of Energy's Energy Information Administration is a well-recognized model that is used to project the potential impact of new electric generation technologies. The NEMS model does not presently have the capability to model energy storage on the national grid.

The scope of this study was to assess the feasibility of, and make recommendations for, the modeling of battery energy storage systems in the Electricity Market Module of the NEMS. Incorporating storage within the NEMS will allow the national benefits of storage technologies to be evaluated.

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The principal investigators for this study were Shiva Swaminathan, William Flynn, and Rajat Sen of Sentech, Inc.

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BES	battery energy storage
CAAA	Clean Air Act Amendments
CNV	California-Southern Nevada Power Area
DOE	U.S. Department of Energy
DSM	Demand-Side Management
ECAR	East Coast Area Reliability Coordinating Agreement
ECP	Electricity Capacity Planning
EFD	Electricity Fuel Dispatch
EFP	Electricity Finance and Pricing
EIA	Energy Information Administration
EMM	Electricity Market Module
ERCOT	Electric Reliability Council of Texas
FGD	flue-gas desulfurization
FL	Florida
LDC	load-duration curve
LDSM	Load and Demand-Side Management
LP	linear programming
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
NE	New England
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NWP	Northwest Power Pool
NY	New York
O&M	operations and maintenance
PV	photovoltaic
RA	Rocky Mountain Power Area & Arizona-New Mexico Power Area
RFM	Renewable Fuels Module
SERC	Southeastern Reliability Council
SMUD	Sacramento Municipal Utility District
SNL	Sandia National Laboratories
SOLES	Solar-Electric Submodule
SPP	Southwest Power Pool
ST	solar-thermal
STV	Florida separated from the Southeastern Reliability Council
UBS	Utility Battery Storage
WES	Wind Energy Submodule
WSCC	Western Systems Coordinating Council

1. Executive Summary

There are three possible avenues for including storage technologies within the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS). The first is to add storage technology as a peak-generation candidate in the Electricity Capacity Planning submodule of the EMM and allow it to compete with other peak-generation technologies for market share. This option would enable a utility to store low-cost off-peak electricity in battery energy storage (BES) systems and supply it during peak demand periods. While such an application for BES has been considered in the past, the overwhelming evidence has been that the difference in the marginal cost of production between peak and off-peak periods is not large enough to warrant investment in BES facilities. Thus, this option will not be evaluated any further. The second method is to consider storage technologies as a demand-side management (DSM) option within the Load and Demand-Side Management (LDSM) submodule and allow storage to compete with other DSM technologies. Unfortunately, this study indicates that the LDSM submodule must be further refined before a determination can be made of how to incorporate BES systems. The third possibility is to integrate storage with renewable technologies in order to make renewable technologies more reliable from a system operations perspective and to command better prices for the energy they generate.

The study recommends that analytical work be carried out with respect to the third option of integrating storage with renewable technologies and that a thorough assessment be made of the potential benefits storage can bring to renewable generation technologies. Formulation of costs associated with the integrated plant, and an assessment of benefits this could bring about within the existing NEMS framework, will have to be undertaken to determine the net gain.

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2. Introduction

In 1995, the Utility Battery Storage (UBS) Program, which is conducted by Sandia National Laboratories (SNL), published a report entitled *Battery Energy Storage for Utility Applications: Phase I - Opportunities Analysis.*[1] This study defined applications for BES systems in the emerging deregulated electric utility industry and made some preliminary estimates of the potential national benefits that would accrue from the large-scale introduction of BES. The intent of the UBS Program was to refine these preliminary estimates through more detailed studies.

A detailed analysis of the benefits of BES systems can be obtained through a top-down approach. This approach will estimate the national benefits of BES systems through the use of general equilibrium models that are used for forecasting national energy supply-and-demand patterns. The NEMS, developed and maintained by the U.S. Department of Energy (DOE) Energy Information Administration (EIA), is a general equilibrium model that was developed both as a forecasting tool and as a tool for evaluating the potential national impacts of alternative national energy scenarios. The Annual Energy Outlook (AEO) projections made by the EIA are the computations made by the NEMS simulations which, despite their recognized limitations, are well accepted by the DOE and the energy industry. Consequently, the NEMS model was considered to be well suited for estimating the national benefits of BES systems. Unfortunately, the NEMS model as it exists does not allow BES to be easily incorporated.

The purpose of this study was to assess the feasibility of, and to make recommendations for, the modeling of BES in the EMM of the NEMS. The interactions between the various submodules of the EMM were investigated. The methodologies for incorporating storage as a stand-alone dispatchable unit and for modeling storage with renewable generation as an integrated unit were assessed.

If the additional cost of integrating storage with renewable generation technologies is lower than the additional benefits it can bring about, the competitiveness and penetration of renewable technologies will be increased. The NEMS can model an integrated renewable unit as another renewable technology with an increased capital and operations and maintenance (O&M) cost. If the additional benefit stream is not accounted for, this integrated unit, when put in competition with other generation technologies for market share, will not be competitive. The additional benefit stream, which the NEMS has the potential to incorporate, includes the benefits associated with dispatchability of renewable units at the system dispatcher's discretion (increased capacity credit) and the ability of an integrated renewable unit to store energy and make it available when it can garner the highest price. This report will discuss how such modeling changes can be brought about.

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3. Organization of Report

Section 4 of this report presents an overview of the EMM as well as the different submodules of EMM, which include the following:

- Electricity Capacity Planning (ECP)
- Electricity Fuel Dispatch (EFD)
- Electricity Finance and Pricing (EFP)
- Load and Demand-Side Management (LDSM)

Section 5 discusses the linkages of the Renewable Fuels Module (RFM) with ECP and the manner in which renewables compete with fossil and nuclear fuel technologies.

Section 6 details the shortcomings of treating renewables in the current manner and describes possible modifications. Also discussed are avenues for value addition by integration of storage with renewables that do not exist with the RFM in its present form.

Section 7 recommends ways in which storage can be incorporated into the EMM. It also proposes methodologies that would allow one to quantify the "value added" by storage in an integrated renewable energy system. Integration of storage results in increased system dispatchability of renewable generation technologies and enables the integrated renewable unit to store energy and make it available when it can garner the highest price. Defining an optimized integrated renewable energy system is vitally important in this analysis, as the increased cost of storage has to be balanced against the increased value such a storage system provides.

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4. The Electricity Market Module of the NEMS

The EMM addresses the electricity supply component of the NEMS. The EMM handles the generation, transmission, and pricing of electricity. In the EMM, electricity generation nationwide is represented by the 13 electricity supply regions listed below. The areas encompassed in these regions are shown on the map in Figure 4-1.[2]

- ECAR - East Coast Area Reliability Coordinating Agreement
- ERCOT - Electric Reliability Council of Texas
- MAAC - Mid-Atlantic Area Council
- MAIN - Mid-America Interconnected Network
- MAPP - Mid-Continent Area Power Pool
- SPP - Southwest Power Pool
- FL - Florida
- STV - Florida separated from the Southeastern Reliability Council (SERC)
- RA - Rocky Mountain Power Area & Arizona-New Mexico Power Area
- NWP - Northwest Power Pool
- CNV - California-Southern Nevada Power Area
- NE - New England
- NY - New York

Six of these regions correspond to North American Electric Reliability Council (NERC) regions: ECAR, MAAC, MAIN, MAPP, SPP, and ERCOT. The three remaining NERC regions are divided into a total of seven clusters to isolate key states or areas. Similarly, in SERC, FL is separated from the rest of the region and called STV. The Western Systems Coordinating Council (WSCC), on the other hand, is partitioned into three subregions: RA, NWP, and CNV. The Northeast Power Coordination Council (NPCC) is split up into two components: the NE and NY.

The interaction between the EMM and the remainder of the NEMS is illustrated in Figure 4-2. The ECP submodule evaluates generation technology options that are needed to meet future demand for electricity and comply with environmental regulations. These options include investments in new utility and nonutility plants (excluding cogenerators), demand-side management (DSM) programs, and pollution control equipment.

The EFD submodule makes dispatching (operating) decisions and determines the allocation of available capacity to meet the demand for electricity in the current year. Using investment expenditures from the ECP and operating costs from the EFD, the EFP submodule calculates the price of electricity, accounting for state-level regulations involving the allocation of costs.

The LDSM submodule translates annual demands for electricity into distributions that describe hourly, seasonal, and time-of-day variations. These distributions are used by the EFD and ECP to determine the quantity and types of resources that are required to ensure reliable and economical supplies of electricity. The LDSM also uses end-use technology cost and performance data from the NEMS demand modules to develop DSM options. These options are placed in competition with supply options in the ECP to determine the most economical approach to meeting future electricity demands.

In addition to these functions, the EMM represents interregional and international transmission and trade within the EFD and ECP submodules. Table 4-1 lists the variables exogenous to the EMM along with the endogenous variables computed by the EMM's interactions with the remainder of the NEMS.

All generation technologies within the NEMS are compared on the basis of total capital and operating costs incurred over a 30-year period.[3] As new technologies become available they compete against conventional plant types. Construction lead time contributes to uncertainty about investment decisions. Technologies with long lead times are subject to greater financial risk, compared to plants with shorter lead times. Plants with long lead times are more sensitive to market changes in interest and inflation rates and are more vulnerable to uncertain demand projections that determine the need for new capacity. To capture these factors, each technology is adjusted using risk premiums based on construction lead time. Wind plants, due to their modular design and short construction time, have low risk premiums. Hence, any increase in capital cost of generation technologies will make modular designs with short construction time more attractive.

Initially, investment decisions are determined in the ECP submodule using cost and performance characteristics that are represented as single-point estimates

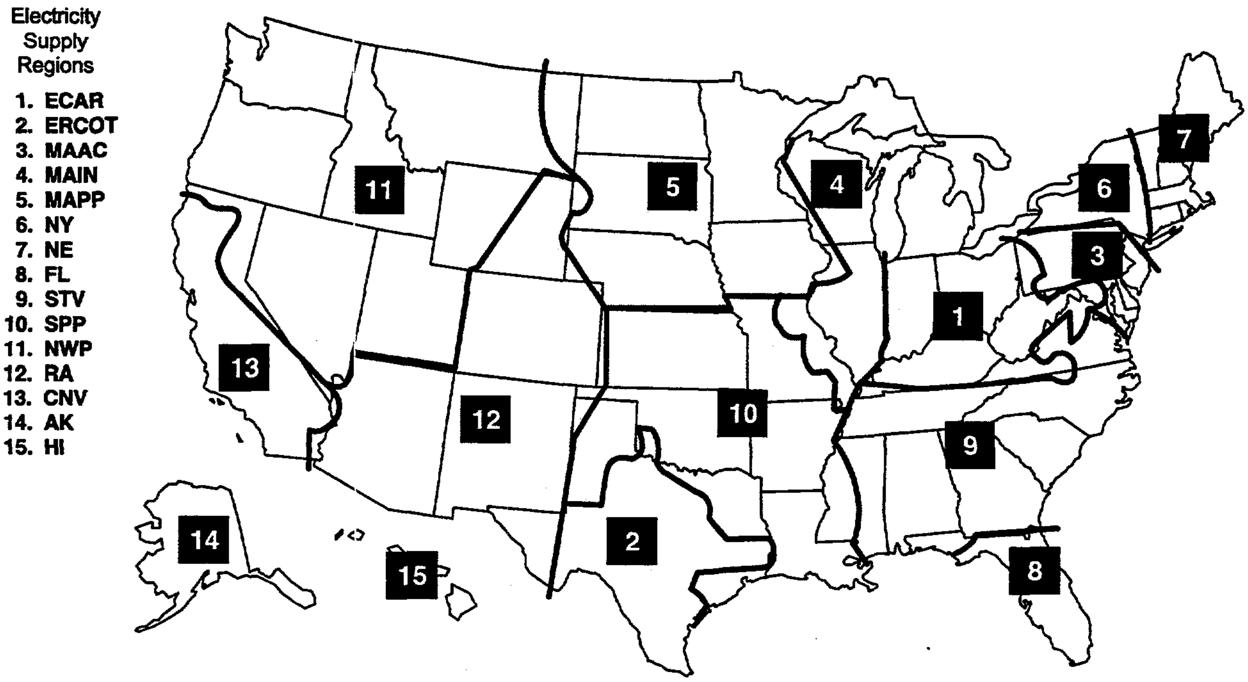


Figure 4-1. Electricity Market Module Supply Regions.

corresponding to the average (expected) cost. If the probability distribution of the average cost of two technologies overlaps, a market-sharing algorithm is used to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are "competitive" but do not have the lowest average cost.

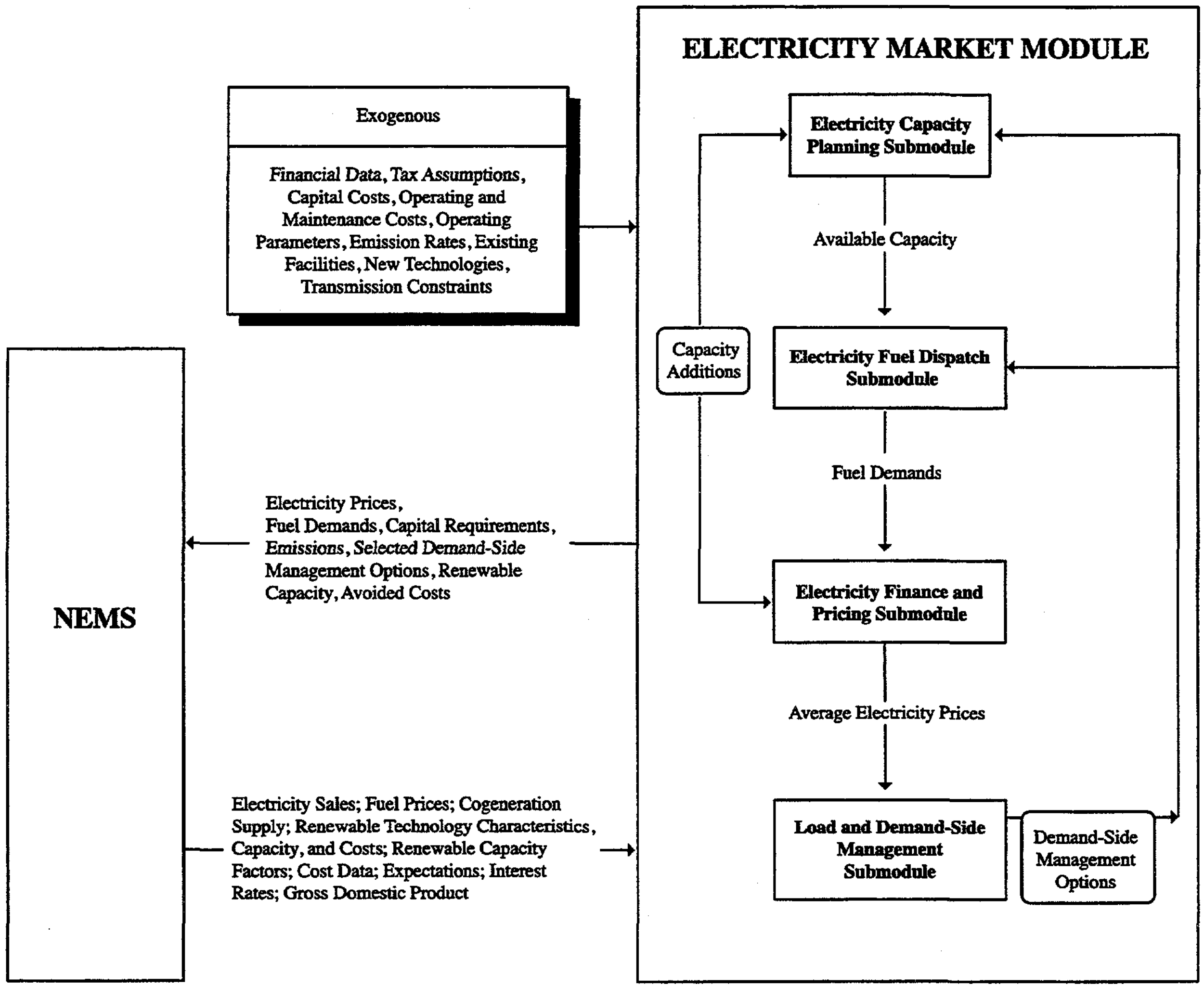
After selecting a new capacity to build in a given year, the ECP submodule passes the total available capacity (old and new) to the EFD submodule and new capacity expenses to the EFP submodule.

Electricity Capacity Planning (ECP) Submodule

The ECP considers various generation options and projects how the electric utility industry will change its generating capability in response to changes in environmental regulations and increases in demand. The ECP contains a dispatching component so that planning decisions consider the trade-off between investment and operating costs.

The ECP examines strategies for complying with environmental legislation, such as the Clean Air Act Amendments of 1990 (CAAA), limits on carbon emissions, and externality costs. Planning options for achieving the emissions restrictions in the CAAA include installing pollution control equipment on existing power plants, implementing DSM programs, and building new power plants with low emission rates. The ECP also considers the banking of emissions allowances for future use. These methods for reducing emissions are compared to dispatching options such as fuel switching and allowance trading. Environmental regulations also affect capacity expansion decisions. For example, new plants are not allocated emissions allowances under the CAAA. Consequently, a decision to build a plant with a particular capacity cannot be made without taking into account the cost, if any, of obtaining sufficient allowances. This could involve purchasing allowances or overcomplying at an existing unit. The ECP is also capable of incorporating regulations for carbon emissions and externality costs for various pollutants.

Potential options for new generating capacity include fossil fuel, nuclear, and intermittent renewable-resource-based power plants such as solar and wind. The ECP includes construction of new generation and transmission capacity in Canada for export to a U.S. region and/or in one U.S. region for export to another U.S. region. As new technologies become available, they will compete with conventional plant types as sources of supply. The ECP considers the impacts of learning effects, risk, and uncertainty. The ECP also puts into competition supply and demand options through the use of DSM programs.



Source: Reference 2

Figure 4-2. Structure of the Electricity Market Module.

Table 4-1. Variables of the Electricity Market Module

Important EMM Outputs	Important Inputs from NEMS	Important Exogenous Inputs
Electricity prices & price components	Electricity sales	General financial data
Fuel demands	Fuel prices	Tax assumptions
Capital requirements	Cogeneration supply	Capital costs
Emissions	Renewable technology characteristics & capacity	O&M cost
DSM options	Renewable technology capacity factor	Operating parameters
	Gross domestic product	Emission rates
		New technologies
		Existing facility

The ECP submodule has a wide range of technologies categorized by fuel type, namely fossil-fired, nuclear, and renewable generation. Coal technologies with various flue-gas desulfurization (FGD) systems, combined cycle plants, and combustion turbines provide most of the new capacity additions. Fuel cell plants were also recently added to the database. Pumped-storage hydro is the only storage technology in the database. A list of all generation technologies is given in Table 4-2.

The ECP uses a linear programming (LP) formulation that examines the trade-off between capital and operating costs to determine capacity planning decisions. It simulates least-cost planning and competitive markets by selecting strategies for meeting expected demands and complying with environmental restrictions that minimize the discounted present value of investment and operating costs. The ECP determines decisions for a 6-year planning horizon and uses multiyear optimization by solving all the years simultaneously.[3]

The ECP relies on a composite load profile for each of the 13 regions to determine demand and dispatch generating units to meet that demand. In each region the load data is averaged and the load-duration curve (LDC) is constructed as follows:[4]

1. The year is split into three seasons: summer, winter, and spring/fall.
2. In each of the seasons, the data for any 24-hour period is subdivided into three time periods covering morning/evening, daytime, and night.
3. An average load is then calculated for each of the three periods for each of the three seasons.
4. The calculated average load is expected to be constant for each of the three time slices in a given season.

This averaging process yields nine datapoints. Two additional datapoints are obtained by taking an average of 2% of the peak loads for each of the summer and winter periods. The 11 load datapoints arranged in descending order produce the composite LDC for a particular region. Figure 4-3 illustrates a composite LDC. The two initial segments refer to the summer and winter peaks, and the remaining nine segments represent the nine datapoints. Thus, for segment 1, which may refer to summer daytime loads, the height represents the average demand during summer daytime. The time period represented by the width of segment 1 will correspond to the total summer daytime hours. Thus, the total hours for the year adds up to 8,760 hours along the time axis.

The decision variables in the ECP submodules include the following: building new generating capacity (conventional and advanced, renewable and nonrenewable technologies), trading firm power (interregional and international), installing pollution control devices at existing units, and banking emissions allowances (i.e., overcomplying in a particular year and saving the allowances for future use). The LP model determines the appropriate mix of supply and demand options that will meet the environmental regulations and provide reliable and economical supplies of electricity over the planning horizon.

Reliable electricity supplies for each region are represented in the LP by a set of constraints that ensures that sufficient generating capability is available to meet the load requirements in each of the 11 load segments and that the minimum reserve margin requirement is met. Dispatchable capacity types can satisfy capacity and energy requirements for any or all of the load segments. Their utilization depends primarily on their availability, fuel constraints, and the relative economics of the potential options. Dispatchable plant types receive full credit towards reliability requirements because they can be readily used when required, as long as they are not out of service. Contributions from intermittent technologies are limited to the appropriate load segments, depending on the availability of the resource (e.g., wind or sun). Intermittent technologies receive a partial capacity credit depending on their capability to provide energy. Section 5 will discuss this in detail.

Generation expansion is achieved in the most economical manner by minimizing the objective function of the LP, which accumulates the total present value of expenditures associated with investment and operating decisions during the planning horizon. Some of the relevant costs associated with the planning horizon are incurred after the end of the planning horizon; hence, the ECP evaluates each option on the basis of a 30-year life-cycle cost. For instance, capital costs (e.g., construction expenditures, interest charges) associated with investment decisions are recovered over the economic life of the asset. The cost coefficient for each investment decision is the sum of the present value of the annual revenue requirements (e.g., depreciation, taxes) over the 30-year period.

Similarly, operating costs are determined for 30 years so that factors such as escalating fuel costs can be taken into account. For each operating decision variable in the first 5 years of the model, the cost coefficient is the present value of the corresponding annual

Table 4-2. Technologies Considered by the ECP Submodule

Fossil-Fired	
Coal without FGD (SO$_2$ standard < 1.2 lb/MMBtu)	Coal without FGD (SO$_2$ standard < 2.5 lb/MMBtu)
Coal without FGD (SO$_2$ standard < 3.34 lb/MMBtu)	Coal without FGD (SO$_2$ standard > 3..34 lb/MMBtu)
Coal with FGD (SO$_2$ standard < 1.2 lb/MMBtu)	Coal with FGD (SO$_2$ standard < 2.5 lb/MMBtu)
Coal without FGD (SO$_2$ standard < 3.34 lb/MMBtu)	Coal without FGD (SO$_2$ standard > 3.34 lb/MMBtu)
New pulverized coal with FGD	Advanced clean coal technology
Conventional gas/oil combined cycle	Advanced combined cycle
Conventional combustion turbine	Advanced combustion turbine
Fuel cells	
Nuclear	
Conventional nuclear	Advanced nuclear
Renewables	
Conventional hydropower	Pumped storage hydropower
Geothermal	Solar-thermal
Solar-photovoltaic	Wind
Wood	Municipal solid waste

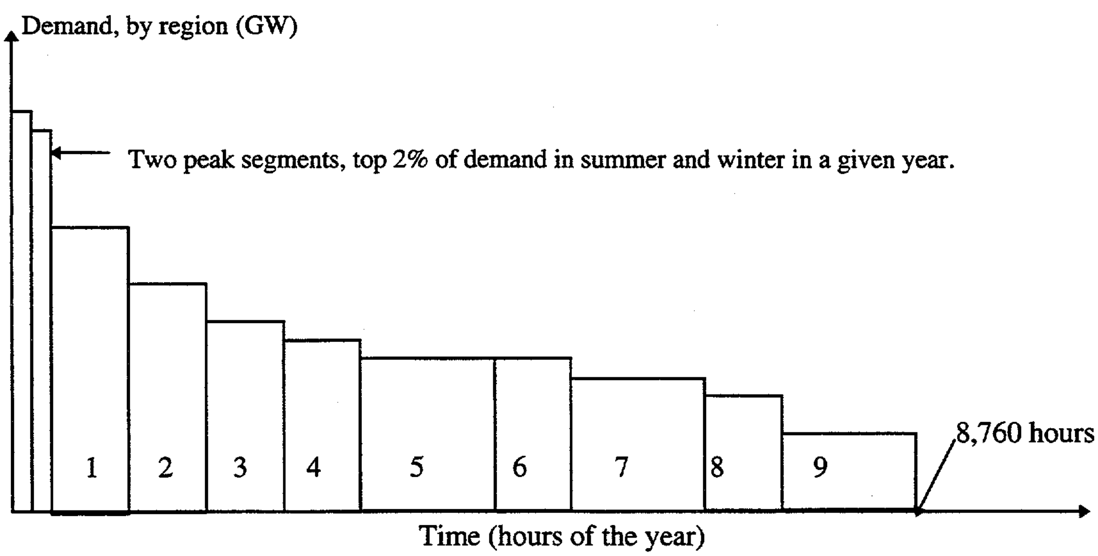


Figure 4-3. Construction of the Load-Duration Curve.

fuel, operations, and maintenance costs. In the last year of the planning horizon, each cost coefficient represents the sum of the present value of operating costs for the next 25 years.

The ECP also provides the capability to incorporate "technological optimism" and learning factors to represent changes in capital costs for new technologies. Before the introduction of a given technology, cost estimates are subject to a great deal of uncertainty. Typically, the cost of building the initial unit for a given technology (referred to as the first-of-a-kind cost) is underestimated due to the lack of information and/or unrealized expectations. This uncertainty tends to decrease as subsequent units become operational and additional data become available. Also, capital costs for new technologies tend to decrease as they penetrate due to learning-by-doing effects and the realization of economies of scale. These cost reductions continue until an equilibrium point is reached and no further decreases are observed (nth-of-a-kind cost). In the LP model, the objective function coefficient for a capacity expansion option in any given year is the product of the nth-of-a-kind cost, the technological optimism factor, and the learning factor.

A market-sharing algorithm is also included in the ECP to revise the capacity expansion decisions determined by the LP model. The algorithm compares the available options on the basis of average costs and selects the options that result in the minimum combination of fixed and variable costs. The LP solution generally consists of a mixture of options since there are different needs to be satisfied (e.g., baseload, intermediate, and peaking requirements), but it will choose to satisfy the needs within each market using the option with the lowest average cost as long as available supplies are sufficient.

Costs are typically represented by distributions rather than a single-point estimate. If the distributions of two or more options overlap, then the technology with the lowest average cost (i.e., the option that will be selected by the LP) is not likely to capture the entire market because some of these units will be more expensive to build than some units of another capacity type with a higher average cost. The market-sharing algorithm examines the solution from the LP model and reallocates some of the capacity expansion decisions to options that were not selected but had "competitive" costs. Competitive costs are calculated in the ECP using the ratio of the relative marginal cost of the technology not selected to the marginal cost of the technology that was selected. Market share is then calculated using a logit function (S-shaped curve bounded in the interval (0,1) such that $y \to 0$ when $x \to -\infty$ and $y \to 1$ when $x \to +\infty$) that reallocates some of the market to options that were not selected by the LP.

Electricity Fuel Dispatch (EFD) Submodule

The EFD determines the annual allocation of available capacity, as determined in the ECP, to meet demand on a least-cost (merit-order) basis subject to current environmental regulations.[5] First, available capacity is ranked from the least to the most costly units according to variable costs. Second, the units are dispatched in this order (from least to most costly) until demand is satisfied. Utilities have the option of purchasing or selling energy to neighboring regions if it is economical to do so.

Utilization of capacity is used to determine fuel consumption and emissions of sulfur dioxide, nitrogen oxide, and carbon. Fuel consumption is provided to the fuel supply modules, while fuel and variable O&M costs are used to determine electricity prices in the EFP. Electricity prices are provided to the demand modules to determine electricity demand.

The merit order determined by the EFD essentially involves a trade-off between operating and emissions costs for each segment of the load duration curve for each of the 13 EMM regions. A Lagrangian approach (similar system lambdas) is used in the EFD to calculate the trade-offs.

Electricity Financing and Pricing (EFP) Submodule

The EFP is a regulatory accounting model that projects electricity prices.[6] The model first solves for revenue requirements by building up a rate base, calculating a return on rate base, and adding the allowed expenses. Electricity prices are determined by allocating projected revenue requirements to each customer class and dividing by the corresponding sales. Because the EFP is an aggregate model, the revenue requirements are allocated according to a representative rate structure for an entire region. The EFP simulates the traditional original-cost or rate-of-return regulatory method where electric utilities have their rates set by local, state, or federal regulatory commissions. Utilities have rates set so as to allow them to recover their operating costs and earn a rate of return equal to their cost of capital.

In an approach similar to that of the EFD, the EFP employs a number of complex algorithms to build the rate base, allocate sales, determine the price of electricity, construct pro forma financial forms, etc.

Load and Demand-Side Management (LDSM) Submodule

The purpose of the LDSM is to explicitly incorporate utility decision-making with regard to utility-sponsored DSM programs into the EMM modeling framework.[7] The LDSM also performs the important function of translating total electricity consumption forecasts into the 13 EMM system LDCs needed for the ECP and EFD. The LDSM contains a database that maps residential and commercial sector equipment energy usage against load-duration segment to assess the costs of DSM programs. These data are initially screened in the LDSM to determine the most cost-effective options. These options are then sent to the ECP, where they are placed in competition in the LP against supply-side options. The options chosen in the ECP are sent back to the LDSM, where the relevant LDC is decremented by the amount and market penetration of the DSM options.

Inclusion of Battery Energy Storage Systems in the Electricity Market Module

Storage technologies such as pumped hydroelectric plants are already included in the EMM. Pumped storage facilities are site-specific, and the addition of new facilities is determined by the availability of favorable geographic sites with large heads between two storage reservoirs. Hence, the NEMS does not project possible market share of pumped storage plants, but incorporates plants that are planned at specific locations. The NEMS provides capacity credit to these plants in the ECP module to meet the system demand. All new pumped storage plants are incorporated in the year they are expected to be commissioned.

The location of BES systems, on the other hand, is not restricted by geographic site considerations. BES plants can be modeled as conventional peaking plants, and could compete against other peaking generation plants such as combustion turbines. Competition among generation technologies is based on life-cycle costs. The least-cost generation expansion plan minimizes the discounted present value of investment and operating costs. BES, charged by off-peak electricity, may have lower fuel and operating costs, but at present has a capital cost higher than conventional peak generation units. However, projections are that BES will be competitive by the year 2010. The ECP module provides a formulation by which cost reduction associated with learning-curve effect and economies of scale could be incorporated. These costs will have to be well defined before modeling BES as a candidate plant in the ECP.

If the battery storage technology is chosen by the ECP, then the variable O&M costs will be passed to the EFD module, and the plant will be dispatched in merit order for the applicable segment of the LDC. The sum of the fixed and variable costs plus the return on capital, allocated by customer class, will determine the price of battery storage energy. The fuel associated with BES is off-peak electricity, which, if BES systems are widely introduced, will alter the LDC. Any changes in the LDCs brought about by widespread introduction of storage will have to be adjusted iteratively. Automation of this iterative process will be cumbersome and will add to the complexity of the model. If the impact on the LDC is disregarded, the modeling of BES as a peaking plant in the EMM is relatively straightforward; however, it will be a rather simplistic rendition of a rather complex system.

If BES is considered as a DSM option (contained in the LDSM database), it will be sent to ECP, where it will compete in the LP against supply-side options. In other words, ECP will decide the relative economics of reducing demand with a DSM technology versus adding new generation technology to meet the demand without attempting to reduce it. If BES is picked by ECP, it will be sent back to LDSM, where the relevant LDCs will be adjusted to the extent to which penetration is achieved.

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5. Renewable Fuels Module

The purpose of the RFM is to define the technological cost characteristics of renewable energy technologies and the size of available resources by class type.[2] These characteristics are used to compute a levelized cost to compete against other similarly derived costs from other energy sources and technologies. The competition of these energy sources over the NEMS time horizon determines the market penetration of these renewable energy technologies. The characteristics that determine the competitiveness of each resource and the interaction of the RFM with the EMM are illustrated in Figure 5-1. The variables of the RFM are listed in Table 5-1.

The wood, municipal solid waste, geothermal, and alcohol fuels submodules of the RFM basically compete against fossil fuels as capacity additions in the ECP. Submodules of the RFM that are relevant for storage technologies are the Wind Energy Submodule (WES) and the Solar-Electric Submodule (SOLES).

Wind Energy Submodule (WES)

The objective of the WES is to project the cost, performance, and availability of wind-generated electricity and to provide this information to the ECP for the building of new capacity in competition with other sources of electricity generation. The ECP provides to the WES information on installed wind capacity after convergence is reached. The WES then calculates the remaining wind resources available for future installations. This accounting of remaining resources is needed since wind energy consists of limited quantities of high-quality resources that are depleted as turbines are installed on windy sites.

The most important task of the WES is to produce energy supply curves from wind resource and wind turbine cost/performance data. This is accomplished by calculating, for three wind classes (wind classes 4, 5, and 6, described in Table 5-2) the maximum conceivable turbine capacity that could be installed, given the available land area, the wind resource, and the current year's turbine capacity factor. The two data arrays constructed within the module for each of the 13 regions and considered within the EMM are as follows:

- Yearly available capacity per wind class per region. This array is constructed to include all the available wind capacity in a region by class. As the ECP picks wind capacity in a particular region, that amount of available wind capacity is removed from the available category in the respective wind class.

- The capacity factors for each wind class for each of the subperiods (slice of the LDC) shown in the composite LDC (Figure 4-3).

Using these two data sets, the model generates a supply curve with a straightforward (deterministic) calculation for wind turbine performance projections. The uncertainties in the results are incorporated in the technological cost and performance projections and in the assumptions about the availability of wind.

Substantial commercial wind installations have been constructed since the early 1980s. Counts of these preexisting installations are used to adjust figures on available windy land at the beginning of the NEMS model run. The WES tracks the quantity of windy land remaining by wind class that is available for future development after each run year by calculating the amount of resource required to provide a given amount of wind installed capacity and subtracting that amount from the total resource available. This assumes that the highest-quality resource (as measured by average wind speed) is used first. These wind classes are represented by specific capacity factors for each region that correspond to time of day and season. The amount of resource used is then subtracted from the previous year's available amount to yield the current year's available windy land. A sample of output for a given regional availability will be of the form: 50 MW of Class 6 resource, 150 MW of Class 5, and 400 MW of Class 4.

Solar Electric Submodule (SOLES)

The objective of the SOLES is to project the costs and performance characteristics of grid-connected solar-thermal (ST) and photovoltaic (PV) electricity-generating technologies and provide them to the ECP for dispatching these technologies in competition with other sources of electricity generation for the purpose of capacity expansion. The SOLES is the repository of data on solar resources, costs, and technology

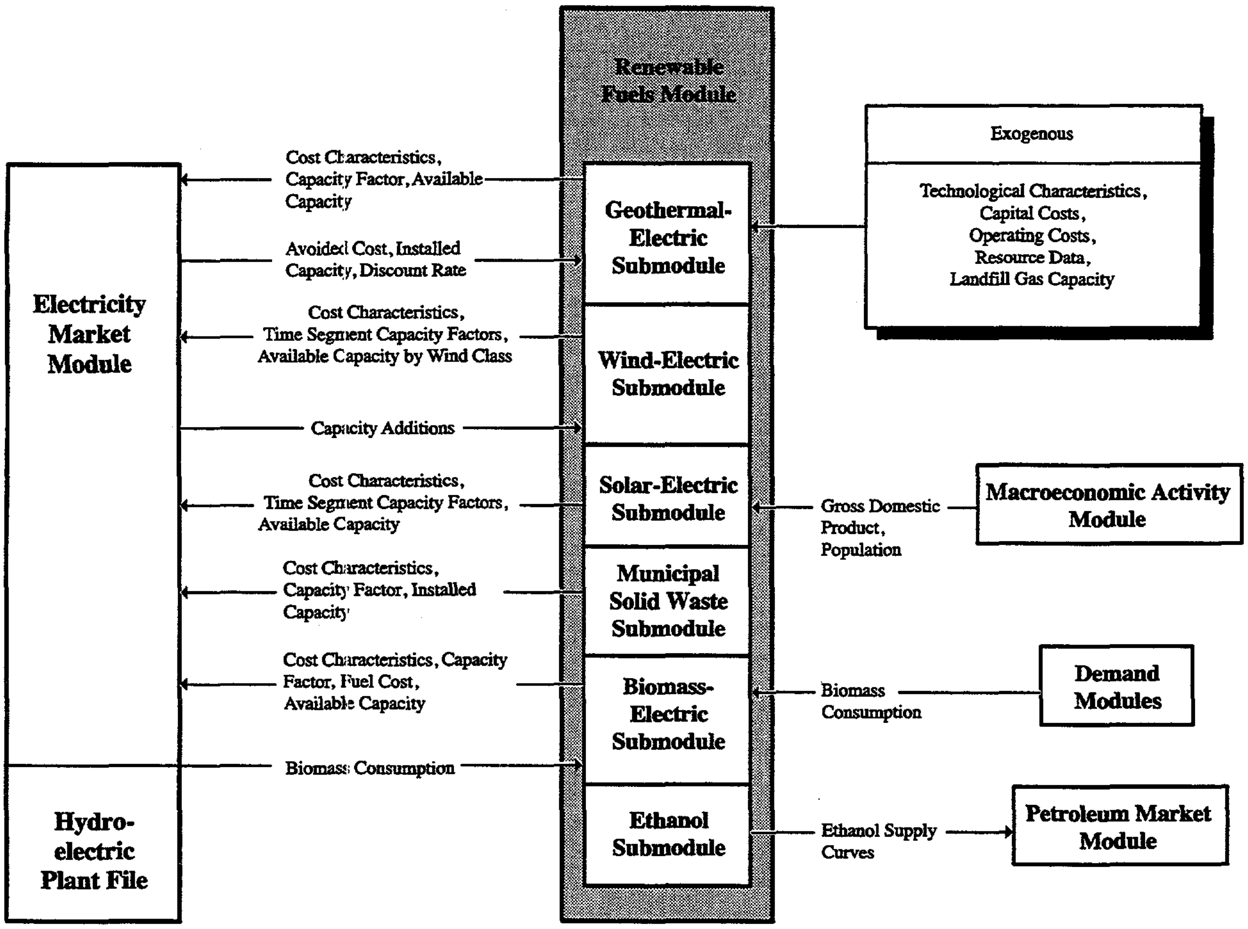

Figure 5-1. Structure of the Renewable Fuels Module.

Table 5-1. Variables of the Renewable Fuels Module

Important RFM Output	Important Inputs from NEMS	Important Exogenous Inputs
Energy production capacities	Installed energy production capacity	Site-specific geothermal re- source-
Capital cost	Gross domestic product	quality data
Operating cost	Avoided cost of electricity	Agriculture feedstock data
Ethanol supply curves	Interest rates	Site-specific wind resource quality data
Capacity factors for solar-thermal, solar photovoltaic and wind electric		Plant utilization (capacity factor)
		Technology cost and performance parameters
		Landfill gas capacity

Table 5-2. Description of Wind Class Categories

Wind Power Class	Height = 10 meters		Height = 50 meters	
	Power (W/m^2)	Speed (m/s)	Power (W/m^2)	Speed (m/s)
Class 4	250	6.0	500	7.5
Class 5	300	6.4	600	8.0
Class 6	400	7.0	800	8.8
Class 7	1000	9.4	2000	11.9

performance characteristics. The SOLES passes the fixed O&M costs, variable O&M costs, and capital costs separately to both the ECP and EFP submodules. The construction lead time in years, as well as the fraction of capital costs in the j^{th} year of construction, are passed to both the ECP and EFP. The SOLES also reflects technological improvements in the cost and performance data.

Data have been developed for a single type of each of the ST and PV technologies to be used for all regions. Accordingly, capital and O&M costs and the efficiency in converting sunlight into electricity are held constant across regions. Any differences in regional resources are captured through the variable that represents the solar energy input to the technology.

ST technologies are composed of concentrators that can only use direct normal radiation. Accordingly, ST data are provided only for 6 of the 13 EMM regions that have sufficiently intense insulation of this kind. The default ST technology is a central receiver with 3-hour molten-salt thermal storage. The resource availability or energy output data for central receiver solar thermal consists of both daytime and evening values for the four seasons for a total of eight values. Since the number of overcast days can exceed the storage capacity of the system, a derating factor is included to reflect this intermittent availability.

The default PV technology is a flat-plate array with one tracking north-south axis tilted at an angle equal to the site's latitude. The availability or energy output is represented as four values representing the average hourly output per unit of system capacity during daytime hours for each of the four seasons defined by the LDC of the EMM.

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6. Integrating Energy Storage with Renewable Generation

As discussed in the previous sections, the ECP submodule uses wind data from the RFM for each of the 13 regions to decide whether to pick wind generation facilities for dispatch. The capacity factors of wind plants vary between seasons and time of day. However, since each of the 11 segments of the composite LDC in Figure 4-3 is defined (e.g., segment 2 is summer evenings, segment 4 is summer nights, segment 5 is fall/spring daytime, segment 9 is fall/spring night), the time segment capacity factors of the wind plant already picked are allocated to those segments to satisfy energy and capacity needs of the LDC.

In the absence of storage there is no mechanism by which electricity generated from wind during low-demand periods (e.g., segment 9, corresponding to nighttime in fall) could be transferred to be used during a period of higher demand (e.g., 5, corresponding to daytime in fall). The value of storage for intermittent energy resources is derived from its ability to shift the electrical energy produced from wind during a lower-value time segment to a higher one. Electricity made available during a higher-value time segment will command a higher price. The cost of electricity production between the higher and lower value segments can vary by as much as a factor of two. This benefit of storage is also illustrated in Figure 6-1, which shows a hypothetical wind resource pattern and system load over a 24-hour period. Although it is an exaggeration, this figure clearly illustrates the point that there can be severe mismatches between periods of peak windpower and periods of peak demand. Storage allows wind energy to be made available for use when it is most needed and therefore garner the highest price.

Another benefit derived from integrating storage with wind is the ability of the integrated system to supply the load with certainty—an ability that an intermittent energy source like wind cannot alone provide. There is some controversy as to the impact of these benefits, particularly during the early phases of market penetration by wind energy systems.

The capacity credit assigned to wind plants by the RFM is 75% of the capacity factor achievable by that particular plant during each of the LDC load segments.[4] In other words, the capacity credit is a function of the capacity capability of the wind technology. The capacity capability is defined as the nameplate capability times the capacity factor. Regions with the best wind power class exhibit a capacity factor as high as 50% during the peak period.[4] Applying a 75% capacity credit to that capacity factor yields 37.5% of the nameplate capacity as the capacity to be counted toward the reserve margin. This percentage is relatively high compared to the customary 15-20% values used by utilities.[4]

There is considerable difference in opinion regarding the capacity credit that can be given to intermittent renewable generation. As a case in point, engineers from the Sacramento Municipal Utility District (SMUD) allow their wind farms to receive only a 15% capacity credit.[8] In contrast, the NEMS model at times assigns capacity credits of as high as ~35-40% to intermittent wind generation; this may be unrealistically high, given utility practice.

This discussion on integration of storage with renewable generation has so far focused on wind energy. However, the same argument applies to solar energy and to solar energy technologies such as photovoltaics and solar thermal. The only difference is that solar resources are usually less intermittent than wind, and consequently the value that an integrated storage-solar system would have compared to a solar generation facility without storage may not be as large as that of wind systems. It is important to point out that solar thermal generation is the only renewable resource that has been seriously considered for storage in large utility-scale systems.

The competitiveness of each technology in the NEMS model hinges on achieving the lowest average (expected) cost per kilowatt-hour produced over the life of the plant. This single-point estimate is derived by dividing all attributable costs by the energy produced by the plant over its lifetime. The denominator will remain unchanged (in fact, the energy produced could decrease due to efficiency losses resulting from the inclusion of storage) with the addition of storage, while the capital cost will increase. This will make the integration of storage with renewables less competitive. The NEMS does not differentiate between two plants generating identical amounts of energy,

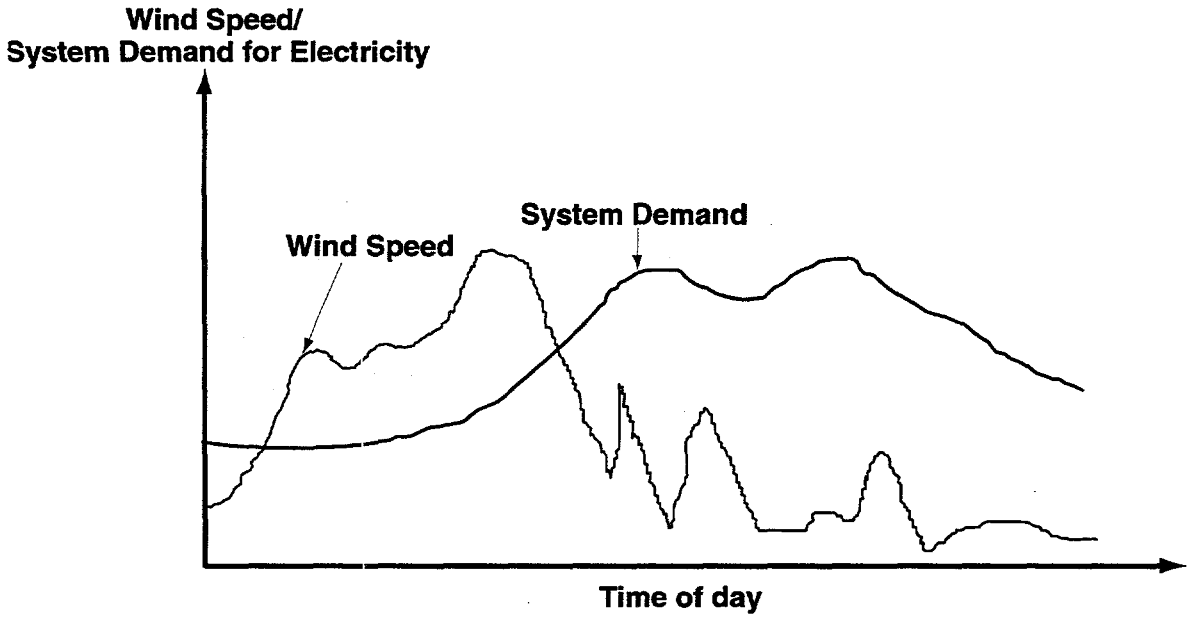

Figure 6-1. Hypothetical Wind Speed Profile—with Opportunity to Store Energy for Use during Period of Peak Demand.

one with certainty and the other without, though the former is of more value to the utility. The NEMS also does not take into account the value of the distributed electricity generation, which is typical in the case of renewable generation. These deficiencies will have to be removed in order to evaluate the integration of storage with renewables within the context of the NEMS.

7. Recommendations

Modeling Storage as Peak Dispatchable Capacity

Modeling storage as peak dispatchable capacity in the EMM is relatively straightforward. Once the relevant performance and cost characteristics of the battery plant are estimated and provided as inputs to the ECP, the storage plant is considered just another peak-generation option. The ECP will then select the appropriate mix of generation plants, with the lowest average cost, to meet the demand growth of the system. The storage plant must be able to compete with other generation options on the basis of low average cost.

As a practical matter, additional programming would be required to model the recharging of the storage plant during off-peak periods. The period of lowest marginal energy cost would have to be identified, and the corresponding capacity would have to be added to the LDC during that period.

This exercise would provide an estimate of the national benefits of load leveling. Such estimates have already been made, and it is generally accepted that the load-leveling benefits of energy storage are not that large. The EMM does not provide the necessary framework to evaluate other benefits associated with storage technologies such as the provision of spinning reserve or frequency regulation or other transmission- or distribution-related benefits.

Integrating BES Systems with Renewable Technologies

The AEO95 projections for the penetration of wind turbines in the U.S. were scaled back substantially in AEO96. The reason for the lower penetration of wind turbines stems from a substantial downward revision of natural gas price projections between 1995 and 1996. Lower natural gas prices make natural-gas-fired generation plants much more cost-effective. The ECP picks generation technologies from candidate plants on the basis of lowest average cost, which includes average capital cost, O&M cost, and fuel cost (all given in cents/kWh). The 10 GW of wind turbine penetration projected (AEO95) to be achievable by the year 2010 is now (AEO96) projected to be achievable by the year 2015.

Storage potentially adds value to renewable energy systems by making them more dispatchable. The NEMS, with modifications, can estimate the value that storage adds to renewable energy systems and project the penetration such integrated systems could achieve.

Storage provides the flexibility to introduce a time shift between renewable energy generation and consumption. The marginal cost of electricity generation to meet the demand in each of the 11 load segments of the LDC (shown in Figure 4-3) is different, with segments with higher demand requiring high-cost peaking units. Enabling renewable generators to shift from low-demand to high-demand periods allows renewables to demand higher prices, increasing the value of renewable generation. The cost differential between high- and low-demand periods within the NEMS varies by a factor of 2. Proper analysis of this differential must be carried out in order to quantify this benefit.

The second benefit associated with the integration of storage is the ability of the integrated unit to supply reliable power on demand. The ability of generating units to supply electricity on demand is crucial for the reliable operation of the power system. Energy generated by intermittent renewable resources may be less valuable to some electricity users and providers. Storage provides the means by which the intermittent resource can be stored and made available on request with certainty. At present some of the wind turbines within the RFM are assigned capacity factors as high as 37.5% of the nameplate power rating of the turbine generator. However, it is customary for utilities to assign lower capacity credits (15-20%) to wind turbines for operational purposes because they are considered unreliable. Storage will be able to provide the means by which to increase the capacity credit assigned to wind turbines. Fossil-fuel plants are assigned a capacity credit of 100% of their nameplate power rating.

The ECP selects candidate plants to meet the growing system demand, both in terms of power and energy. Once a plant is selected, its power rating is subtracted before the next plant is selected to satisfy the remainder of the power needs of the system. This process stops once the system needs are met in a given year. However, when wind plants are selected, only a fraction (this varies depending on the wind sites, but could be as high as 0.375) of their power rating is subtracted. It is anticipated that the integration of storage can increase this fraction. However, quantification of the benefit of higher capacity credit (given in \$/kW) is difficult, as the optimization routine in the ECP module is based on average energy cost of the plant over its lifetime, given in cents/kWh. A proxy variable to reduce the capital cost of storage devices will have to be devised to account for this benefit. The proxy variable could be the capital cost of peak generation units not added as a result of increased capacity credit assigned to the integrated plant.

It is recommended that the following steps be undertaken to assess the value that storage may bring to wind energy generation plants, which will make the wind plants more competitive:

- Define a composite plant type that would combine the cost and operating characteristics of both the intermittent wind turbine generator and storage technologies. This integrated plant will receive a higher capacity credit and would then be analogous to a dispatchable capacity type.

- Determine methods by which higher capacity credits assigned for an integrated plant (compared to a corresponding stand-alone wind turbine) can be valued by the EMM.

- Modify the high capacity factors assigned to some of the renewable generation systems within the NEMS model.

- Assess the relative values of electricity generation for each of the 11 time segments in the LDC and value added by shifting generation from the lower segment to the higher segment. Integrating storage with wind turbines will impact the cost performance in two ways. First, the time-dependent capacity factor could be, within limits, arbitrarily shifted from low-demand periods to periods of highest demand in which marginal cost of electricity is the highest. This will add to the competitiveness of wind since it competes in a higher price regime. The second impact will, in effect, reduce the competitiveness of an integrated wind plant by increasing the capital cost and by incurring conversion losses in the energy storage process, which will result in an overall reduction of the total generation over a year. The trade-off between the two counteracting factors, coupled with the increased capacity credit benefit, will determine whether or not storage will increase or decrease the competitiveness of the wind technology.

- Make a base-case run, with reasonable capacity credits being assigned to wind plants, and assess the penetration of wind. Reconfigure the wind plant as an integrated system with higher capital costs, but with a correspondingly higher capacity credit and higher energy value, rerun the model, and assess the new penetration level.

Battery Storage With LDSM Module

The LDSM module within the NEMS is not developed to handle load management and industrial DSM. Future versions of the model are expected to deal with those options, and a methodology to develop a load shape curved for those applications is discussed in the NEMS literature. Commercial cool thermal storage is explicitly mentioned as future technology that will be incorporated into the NEMS. Modifications to incorporate shifting of loads and variable pricing signals were also once considered by the EIA. However, all such enhancements to the LDSM module have been shelved at this time, although these applications will be very attractive for other storage options. It is recommended that the development of the NEMS in these areas be closely monitored. Participation in any model enhancement process will ensure the model's evolution in a manner suitable for integrating a variety of storage technologies.

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