CHAPTER THREE

Assessing the Electric System Benefits of Clean Energy

Clean energy programs and policies can help states achieve their goal of providing a less polluting, more reliable and affordable electric system that addresses multiple challenges, including:

- Lowering energy costs for customers and utilities alike, particularly during periods of peak electricity demand;[1]
- Improving the reliability of the electricity system and averting blackouts at a lower cost;
- Reducing the need for new construction of generating, transmission, and distribution capacity; and
- Providing targeted reductions in load (i.e., the amount of electric power or the amount of power demanded by consumers at a given time) in grid-congested areas, such as southwestern Connecticut and San Francisco, California.

Many states are evaluating the electric system benefits of clean energy. These benefits, as described above, go beyond the direct energy savings and renewable energy generation impacts discussed in Chapter 2, *Assessing the Potential Energy Impacts of Clean Energy Initiatives.* This chapter provides an overview of methods that can be used to undertake broad assessments of the impacts

DOCUMENT MAP

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[1] *Just as energy efficiency program economics can be evaluated from a variety of perspectives (total resource costs, program administration costs, ratepayer, participant, and society) so can the benefits of clean energy programs. For each perspective, the benefits of clean energy are defined differently. In this guide, we are examining the equivalent of the total resource cost perspective, considering benefits (and costs) to the participants and the utility. While other perspectives including the utility costs are important, we focus on those perspectives most important to policymakers and clean energy program administrators. For more information about the different perspectives used to evaluate the economics of programs, see Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers: A Resource of the National Action Plan for Energy Efficiency, November 2008.* ***www.epa.gov/cleanenergy/documents/cost-effectiveness.pdf***.

STATES ARE QUANTIFYING THE ENERGY SYSTEM BENEFITS OF CLEAN ENERGY POLICIES

Several states have quantified the energy system benefits from their clean energy measures and determined that the measures are providing multiple benefits, including avoiding the costs of electricity generation, reducing peak demand, and improving energy system reliability.

Georgia conducted an assessment of the benefits of achieving energy efficiency improvements in the state and found it could reduce demand for electricity by 3,339 GWh–12,547 GWh in 2010.

In addition to these energy savings, the analysis showed that the improvements could benefit the overall electricity system and:

- Avoid generation in Georgia of 1,207 GWh–4,749 GWh in 2010,
- Reduce regional wholesale electricity cost by 0.5–3.9 percent by 2015, and
- Lower peak demand by 1.7–6.1 percent by 2015 and achieve a number of environmental and economic benefits.

(Jensen and Lounsbury, 2005).

of clean energy on the overall electric system, including effects on electricity generation, capacity, transmission, distribution, power costs, and peak demand.

State legislatures, energy and environmental agencies, regulators, utilities, and other stakeholders (e.g., ratepayer advocates, environmental groups) can quantify and compare the electric system benefits of clean energy resources [e.g., energy efficiency, including some demand response programs such as load control programs, renewable energy, combined heat and power (CHP), and clean distributed generation (DG)] to traditional grid electricity. This information can then be used in many planning and decision-making contexts, including:

- Developing state energy plans and establishing clean energy goals;
- Conducting resource planning (by PUCs or utilities);
- Developing demand-side management (DSM) programs;
- Conducting electric system planning, including new resource additions (e.g., power plants), transmission and distribution capacity, and interconnection policies;
- Planning and regulating air quality, water quality, and land use;
- Obtaining support for specific initiatives; and
- Policy and program design.

Although quantifying electric system benefits can be challenging—particularly when analyzing long-term effects in a complex, interconnected electricity grid—it is important to consider these benefits when evaluating clean energy resources. This chapter presents detailed information about the energy system, specifically electricity benefits of clean energy, to help policy makers understand how to identify and assess these benefits based upon their needs and resources.

- Section 3.1, *How Clean Energy Can Achieve Electric System Benefits,* describes the energy system in the United States and explains the multiple ways that clean energy policies and programs can positively affect the electric system and electricity markets, thereby benefiting consumers, utilities, and society.
- Section 3.2, *How States Can Estimate the Electric System Benefits of Clean Energy,* presents an overview of the methods for estimating the primary and secondary electric system benefits of different types of clean energy resources.
  - Section 3.2.1, *How to Estimate the Primary Electric System Benefits of Clean Energy Resources,* describes the specific basic and sophisticated modeling approaches and associated tools that can be used to quantify a set of typically recognized (i.e., "primary") benefits.
  - Section 3.2.2, *How to Estimate the Secondary Electric System Benefits of Clean Energy Resources,* describes approaches and tools for estimating other electric system benefits (i.e., "secondary" benefits) that are less frequently assessed and often more difficult to quantify.
- Section 3.3, *Case Studies,* presents examples of how two states, California and Massachusetts, are estimating the electric system benefits of their clean energy programs.

3.1 HOW CLEAN ENERGY CAN ACHIEVE ELECTRIC SYSTEM BENEFITS

Energy is crucial to all aspects of the U.S. economy. This section presents background information on how the U.S. energy system is structured (see Section 3.1.1), and describes the wide range of benefits that clean energy can bring to the electricity component of this system (see Section 3.1.2).

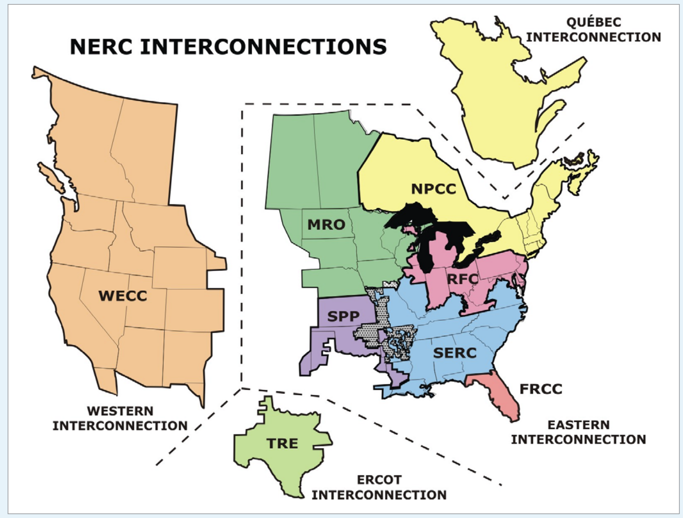
3.1.1 THE STRUCTURE OF THE U.S. ENERGY SYSTEM

The energy system in the United States includes all the steps, fuels, and technologies from the import or extraction of energy resources, to their conversion to useful forms, to their use in meeting end-use energy demands (e.g., by the transportation, industrial, residential, and commercial sectors). Components of the energy supply system include transportation fuels, electricity, and other forms of energy for use in homes, manufacturing, and business. This chapter focuses on several components of the larger electric system: electricity production, transmission, distribution, and the markets by which electricity is bought and sold. These components are hereinafter referred to together as the *electric system*.

The North American electric system acts essentially like four separate systems of supply and demand because it is divided into four interconnected grids in the continental United States and Canada: the Eastern, Western, Quebec, and Electric Reliability Council of Texas (ERCOT) Interconnections. These alternating current (AC) power grids are depicted in Figure 3.1.1, *NERC Interconnections*. Electricity can be imported or exported relatively easily among the numerous power control areas within each interconnection system. However, for reliability purposes, the interconnections have limited connections between them and are connected by direct current (DC) lines.

Balancing the supply of and demand for electricity in an economically efficient manner is complicated by a number of factors. For example, the demand for electricity varies significantly hour by hour, and cyclically by time of day and season. Residential electricity demand peaks in the morning and at night, when more residents are at home and operating heating and air conditioning units, washers, dryers, and other products that use electricity. Commercial and industrial electricity demand varies by type of company or industry, and thus may be considerably different from one location to another.

FIGURE 3.1.1 NERC INTERCONNECTIONS



Source: NERC, 2008.

Electricity supply is matched to demand using a portfolio of production technologies. To meet the demand, some power plants operate almost continuously, serving as baseload units (e.g., coal and nuclear plants are examples of baseload units). Each baseload unit has relatively high capital costs, but operational costs are low. Also, startup and shutdown at these plants takes time, is expensive, and causes additional wear on generating units. Other generation sources are operated only during the times of highest demand, serving as "peaking" units. The output of these generators rises and falls throughout the day, responding to changing electricity demand. Natural gas turbines are often used for this purpose. These technologies are expensive to run for long periods but can be started up and shut down quickly. Because electricity must be generated at the same time it is used, meeting peak demand and the related price volatility are key issues.

The source of the electricity supply can also vary. A group of system operators across the region decides when, how, and in what order to dispatch electricity from each power plant in response to the demand at that moment and based on the cost or bid price. In regulated electricity markets, dispatch is based on "merit order" or the variable costs of running the plants. In restructured markets or wholesale capacity markets, dispatch is based on the generator's bid price into the market. Electricity from the power plants that are least expensive to operate (i.e., the baseload plants) is dispatched first. The power plants that are most expensive to operate (i.e., the peaking units) are dispatched last. The merit order or bid stack is based on fuel costs and plant efficiency, as well as other factors such as emissions allowance prices.

Other conditions also affect electricity supply. Transmission constraints (i.e., when transmission lines become congested) can make it difficult to dispatch electric generators located away from load centers and move their power into areas of high demand, or may require certain units to operate to improve system reliability. Extreme weather events can decrease the ability to import or export power from neighboring areas. "Forced outages," when certain generators or transmission lines are temporarily unavailable, can also shift dispatch to other generators. System operators must keep all these issues in mind when dispatching power plants. States can also take these issues into consideration by using dispatch models or other approaches to estimate which generators would likely reduce their output and their emissions in response to the introduction of clean energy resources.

The electric power transmission system connects power plants to consumers. Figure 3.1.2 depicts the flow of power from the generating station, or power plant, to the transformer and the transmission lines, through the substation transformer (which reduces the voltage) to the distribution lines, and finally, through the pole transformer to the consumer's service box. Electricity *transmission* is typically between the power plant and a substation, and electricity *distribution* is the delivery from the substation to consumers. Electricity is usually transmitted through overhead transmission and distribution lines, although sometimes underground distribution lines are used in densely populated areas. Overlapping lines are provided in the grid so that power can be routed from any power plant to any load center (e.g., populated areas), through a variety of routes. Transmission companies conduct detailed analyses to determine the maximum reliable capacity of each line.

The process of generating, transmitting, and distributing electricity is quite complex and involves many costs. Clean energy provides opportunities for states to reduce many of those costs.

HOW ELECTRIC GENERATORS ARE DISPATCHED

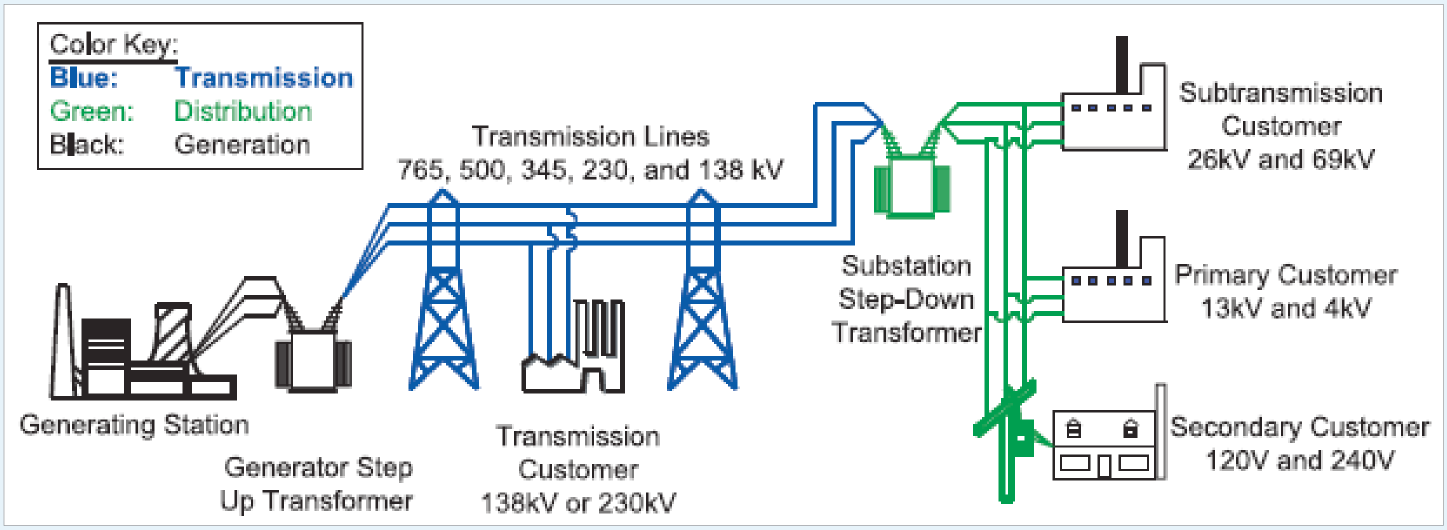
The operation of electric systems is determined by a set of physical constraints and economic objectives, through a process referred to as "economic dispatch." The electric system operator dispatches generating units (i.e., signals generators to start or increase production) in economic merit order—that is, in order of increasing operating costs (starting with the lowest costs adjusted for transmission losses), subject to reliability considerations including transmission constraints. The highest-cost unit dispatched at any point in time is said to be "on the margin" and is known as the "marginal unit." For example, high-cost combustion turbines and gas/oil peaking units are on the margin for many hours of the week. During off-peak times, plants with lower operating costs (e.g., combined cycle gas turbines and coal-fired steam units) can be on the margin. In some regions the cost used for dispatch is the variable cost of running each plant (mainly fuel cost), but in others the criterion for dispatch is a bid price submitted by the owners of the generators.

3.1.2 PRIMARY AND SECONDARY BENEFITS OF CLEAN ENERGY

Clean energy initiatives can result in numerous benefits to the electric system, predominantly through the avoidance of costs associated with generating, transmitting, and distributing electricity. Clean energy is often cheaper than or just as cost-effective as other energy options, while delivering important electric system, environmental, and/or economic benefits to the state. For example, in California, energy efficiency programs have cost the state 2¢–3¢ per kWh on average—much less than the cost of new generation, which can be more than 6¢ per kWh for new natural gas combined cycle plants—while reducing the need for new power plants and increasing reliability (NRDC, 2006). Consequently, quantifying the electric system benefits of clean energy options is central to sound policy planning, contributes to public confidence in clean energy policies, and helps policy makers choose among different approaches to delivering clean energy.

The benefits of clean energy initiatives are categorized in this document as primary and secondary benefits. *Primary benefits* are those electric system benefits that are conventionally recognized for their ability to reduce the overall cost of electric service over time. These benefits can occur over the long run, the short run, or both. Some of these benefits are significant and most can be quantified using well-tested methods. *Secondary benefits* of clean energy are less frequently recognized than primary benefits, and tend to be smaller and/or harder to quantify. Nevertheless, it is useful to identify

FIGURE 3.1.2 FLOW OF ELECTRICITY FROM POWER PLANTS TO CONSUMERS



Source: US-Canada Power System Outage Task Force, 2004 https://reports.energy.gov/BlackoutFinal-Web.pdf.

these benefits and quantify them, when possible, in order to most accurately reflect both the costs and benefits of clean energy.

The *primary electricity system benefits* of clean energy include:

- *Avoided costs of electricity generation or wholesale electricity purchases*. Clean energy policies and programs can displace electricity generated from fossil fuels (e.g., natural gas, oil, and coal-fired power plants). Savings typically appear as avoided fuel costs and reduced cost for purchased power or transmission service.
- *Deferred or avoided costs of power plant capacity*. Clean energy policies and programs can delay or avoid the need to build or upgrade power plants or reduce the size of needed additions. Typical components are the capital investments and annual fixed costs (e.g., labor, maintenance, taxes, and insurance) not incurred as a result of clean energy initiatives.
- *Avoided electric loss in transmission and distribution* (T&D). The delivery of electricity results in some losses due to the resistance of wires, transformers, and other equipment. For every unit of energy consumption that a clean energy resource avoids at the end-use site, it also avoids the associated energy loss during delivery of electricity to consumers through the T&D system.[2]
- *Deferred or avoided costs of T&D capacity*. Clean energy resources that are located close to where energy is consumed can delay or avoid the need to build or upgrade T&D systems or reduce the size of needed additions. These savings can occur over the long run, the short run, or both. Typical components are similar to those for avoided power plant capacity.

Examples of *secondary benefits* include:

- *Avoided ancillary service costs.* Clean energy resources that reduce load, that are located close to where energy is consumed, or that can support smooth operation of the power grid can reduce some ancillary services requirements. Ancillary services are those electric generator functions needed to ensure reliability, as opposed to providing power. Examples include operating reserves (e.g., generators that are up and running to take over if a load-serving generator fails or load spikes) and voltage support (e.g., generators that are running and can tune their output to keep voltage stable). Clean energy resources that reduce the need for ancillary services save fuel and reduce

2 *It is important to note that clean central-station generation incurs the same T&D losses as fossil-fueled sources.*

emissions by allowing some units to shut down and may delay or avoid the need for investment in new generation to provide ancillary services. These include stationary energy storage resources such as batteries and pumped hydro storage. Other clean energy resources, especially demand response resources—such as controls on air conditioning or water heater load control programs—can free up reserves that are needed to respond in the event of a system outage. In some regions, clean energy resources that operate during peak times reduce the required level of operating resources.

- *Reduced wholesale market clearing prices.* Clean energy policies and programs can lower the demand for electricity or increase the supply of electricity, causing wholesale markets to clear at lower prices. This benefit can be dramatic during peak hours.

- *Increased reliability and power quality*. An electric grid is more reliable if the loads are lower, especially during peak hours and in areas where transmission is constrained. Integration of clean energy resources can increase the reliability of the electricity system since power outages are less likely to occur when the system is smaller and not strained; more dispersed resources make the system less vulnerable to outages. In addition, power quality—which is important for the operation of some electrical equipment—can be enhanced by some forms of clean energy resources (e.g., fuel cells).

- *Avoided risks associated with long lead-time investments.* While clean energy resources certainly have some risk (e.g., of underperformance of energy efficiency or renewable energy measures), these resources offer greater flexibility due to their modular, segmented nature, and relatively quick installation and disconnection time compared with traditional resources. As a result, clean energy options increase flexibility to deal with uncertainty (relative to large, traditional fossil fuel resources) by reducing dependence on conventional fuels and allowing planners to be more responsive to deviations from load forecasts. The size of the potential for some clean energy options, such as energy efficiency, is correlated with load, making it especially responsive to changes in the planning environment. In addition, reducing or delaying the need for large utility investments for transmission or generation reduces both the need for large amounts of financing and the chance of failed or unnecessary investments.

- *Reduced risk from deferring investment in traditional, centralized resources until environmental and climate change policies take shape.* Clean energy policies and programs may reduce the cost of future compliance with air pollution control requirements. In addition, clean energy policies and programs may limit exposure to costs from any future carbon regulations.

- *Improved fuel diversity and energy security.* Portfolios that rely heavily on a few energy resources are highly affected by the unique risks associated with any single fuel source (e.g., coal, oil, gas). In contrast, the costs of some clean energy resources are relatively unaffected by fossil fuel prices and thus provide a hedge against fossil-fuel price spikes. Other clean energy resources can be affected by fossil fuel prices. For example, biomass renewables may require fertilizer and/or processing via technologies that use petroleum, natural gas, and/or coal, and because wind provides intermittent power that may not be available at peak demand times, it can require backup peaking units (e.g., natural gas turbines). Overall, however, the greater the diversity in technology the less likelihood of supply interruptions and reliability problems. In addition, using diverse domestic clean energy resources provides energy security by reducing the vulnerability of the electric system to attack and reducing dependence on foreign fuel sources, such as imported petroleum, which may yield political and economic benefits by protecting consumers from supply shortages and price shocks

Table 3.1.1 summarizes the traditional costs of generating, transmitting, and distributing electricity, and describes the primary and secondary clean energy benefits associated with each type of cost.

3.2 HOW STATES CAN ESTIMATE THE ELECTRIC SYSTEM BENEFITS OF CLEAN ENERGY

The rigor with which states can or may want to analyze the electric system benefits of clean energy depends on the type of benefit being analyzed, the clean energy proposal's status in the development and design process, the level of investment under consideration, regulatory and system operator requirements, resources (e.g., computers, staff) available for the analysis and, for some benefits, the utility or region.

TABLE 3.1.1 ELECTRIC SYSTEM COSTS AND THE PRIMARY AND SECONDARY BENEFITS OF CLEAN ENERGY

Traditional Costs	PrimaryBenefits of Clean Energy	Secondary Benefits of Clean Energy	Description of Benefit	Section
Generation				
▪ Fuel ▪ Variable operation and maintenance ▪ Emissions Allowances	▪ Avoided costs of electricity generation or wholesale electricity purchases.	▪ Reduced risk from investment in traditional, centralized resources before environmental and climate change policies take shape. ▪ Improved fuel and energy security.	▪ Clean energy policies and programs can displace traditional electric energy generation.	3.2.1a
		▪ Avoided ancillary services. ▪ Reductions in wholesale market clearing prices. ▪ Increased reliability and power quality. ▪ Avoided risks associated with long lead-time investments (e.g., risk of overbuilding the electric system).	▪ Clean energy policies and programs can lower the demand for electricity or increase the supply of electricity, causing wholesale markets to clear at lower prices.	
▪ Capital and operating costs of upgrades ▪ Fixed operation and maintenance ▪ New construction to increase capacity	▪ Avoided costs of power plant capacity.		▪ Clean energy policies and programs can delay or avoid the need to build or upgrade power plants.	3.2.1b
Transmission & Distribution				
▪ Capital and operating costs of maintenance ▪ Upgrades ▪ New construction	▪ Deferred or avoided costs of transmission & distribution (T&D) capacity.	▪ Increased reliability and power quality.	▪ Clean energy policies and programs that are located close to where energy is consumed can delay or avoid the need to build or upgrade T&D systems.	3.2.1c
▪ Energy losses	▪ Avoided electric loss in T&D lines.		▪ Clean energy policies and programs that avoid energy consumption also avoid losses associated with transmission and distribution.	3.2.1d

A range of basic and sophisticated methods is available to allow analysts to estimate how the electric system will be affected by clean energy measures, including when and where electricity generation may be offset. Basic methods typically include spreadsheet-based analyses or the adaptation of existing studies or information. Sophisticated methods typically use dynamic electric system models that (a) predict the response of energy generation to actions that influence the level of clean energy resources and (b) calculate the resulting effects. These two approaches are not mutually exclusive, but may be used in a complementary way. Table 3.2.1 describes the advantages and disadvantages of each method and when they are appropriate to use.

SELECTING BENEFITS TO EVALUATE

Some states may not be interested in estimating all types of electric system benefits, or states may be considering programs that deliver benefits in only some areas. It is generally common practice to evaluate

TABLE 3.2.1 ADVANTAGES AND DISADVANTAGES OF BASIC VS. SOPHISTICATED METHODS OF ESTIMATING ELECTRIC SYSTEM BENEFITS

Advantages	Disadvantages	When to Use
Basic Estimation		
▪ Relatively low cost. ▪ Requires minimal input data and time.	▪ Less robust. ▪ Provides approximate estimates.	▪ For preliminary studies. ▪ When time and/or budget are limited. ▪ When limited data resources are available.
Sophisticated Simulation		
▪ Robust representation of electric system dispatch and, in some cases, capacity expansion. ▪ Provides high level of analytic rigor and detailed results. ▪ May be available from utility resource planners. ▪ May allow sensitivities to a wide range of assumptions.	▪ Time- and resource-intensive. ▪ Relatively high cost. ▪ Requires significant input data. ▪ Complex. ▪ Not transparent in stakeholder process.	▪ When a high degree of precision and analytic rigor is required. ▪ When sufficient data resources are available.

all the primary benefits for clean energy projects or programs. For secondary benefits, however, the need for detailed estimation can vary depending on several factors, including:

- The type of clean energy resource being considered,
- Regulatory or system operator study requirements,
- Available resources (e.g., computers, staff, and data), and
- Whether certain needs or deficiencies have been identified for the existing electric system.

For example, suppose a state is considering demand response resources such as direct load control (i.e., programs that enable electric providers to reduce the demand of consumer sites at peak times, sometimes by directly curtailing major energy-intensive equipment such as air conditioners and water heaters). For these types of measures, it is increasingly common to consider wholesale market price effects because the benefit to consumers from price reductions during peak hours can be substantial. On the other hand, if a state energy efficiency policy is expected to produce significant savings only during off-peak hours or seasons, which would result in a smaller impact on the wholesale market, it may not be worthwhile to estimate the wholesale market price effects. Similarly, quantification of ancillary service benefits can be difficult in areas without regional transmission organizations (RTOs) that routinely report market prices, even if the clean energy resource has the capability of delivering these ancillary service benefits. In this case, analysts may decide to devote their limited staff and computing power to quantifying benefits that are likely to yield the most reliable and meaningful results, and address other benefits qualitatively.

There are a number of considerations in selecting which benefits to estimate. As indicated earlier, primary electric system benefits tend to be easier to quantify and the methods to quantify them tend to be mature. The methods to evaluate the secondary electric system benefits are more limited and can be subject to debate.

Tables 3.2.2 and 3.2.3 outline some of the factors that states can consider when deciding which electric system benefits to analyze, including available methods and examples, advantages, disadvantages, and purpose of analysis. Section 3.2.1, *How to Estimate the Primary Electric System Benefits of Clean Energy Resources*, and Section 3.2.2, *How to Estimate the Secondary Electric System Benefits of Clean Energy Resources,* review each type of benefit and explain the approaches generally used to analyze each benefit.

TABLE 3.2.2 PRIMARY ELECTRIC SYSTEM BENEFITS FROM CLEAN ENERGY MEASURES

Applicable Clean Energy Resources	Considerations for Determining Whether to Analyze	Who Usually Conducts Analysis?	When is Analysis Usually Conducted or Made Available?
BENEFIT: Avoided electricity generation or wholesale electricity purchases			
▪ All resources. ▪ Resources that operate during peak hours.	▪ Traditionally analyzed in cost-benefit analysis. ▪ Widely accepted methods. ▪ Data generally available but expensive. ▪ Models available but are complex, not transparent, and are often expensive to use. ▪ Many assumptions about technology, costs, and operation needed. ▪ Long term fuel price forecasts must be purchased or developed.	▪ Utilities conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis. ▪ RTO/ISO and the Independent Market Monitor. ▪ US EIA and private consultancies provide electric dispatch and capacity expansion forecasts.	▪ Resource planning and released regulatory proceedings. ▪ Area-specific DSM program development. ▪ RTO/ISO avoided cost estimates may be published on regular schedules.
BENEFIT: Avoided power plant capacity additions			
▪ All resources. ▪ Resources that operate during peak hours.	▪ Traditionally analyzed in cost-benefit analysis. ▪ Generally accepted methods for both estimation and simulation. ▪ Some assumptions about technology, costs and operation needed. ▪ Data generally available.	▪ Utilities conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis. ▪ In some regions, RTO/ISO publishes capacity clearing prices.	▪ Resource planning and proceedings. ▪ Area-specific DSM program development. ▪ RTO/ISO avoided cost estimates may be published on regular schedules.
BENEFIT: Deferred or avoided T&D capacity			
▪ Resources that are close to load, especially those that operate during peak hours.	▪ Traditionally analyzed in cost-benefit analysis. ▪ Load flow forecast availability. ▪ Unit cost of T&D upgrades can be estimated but may be controversial. ▪ T&D capacity savings reasonably practical, but site-specific savings difficult to generalize.	▪ Utilities conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis. ▪ RTO/ISO.	▪ T&D build planning. ▪ Area-specific DSM program development. ▪ RTO/ISO costs estimates may be published on regular schedules.
BENEFIT: Avoided energy loss during T&D			
▪ Resources that are close to load, especially those that operate during peak hours .	▪ Traditionally analyzed in cost-benefit analysis. ▪ Straightforward; easy to estimate once avoided energy has been calculated ▪ Loss factor for peak savings may need to be estimated.	▪ Utilities collect loss data regularly and may conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis.	▪ Resource planning and proceedings. ▪ Area-specific DSM program development.

TABLE 3.2.3 SECONDARY ELECTRIC SYSTEM BENEFITS FROM CLEAN ENERGY MEASURES

Applicable Clean Energy Resources	Considerations for Determining Whether to Analyze	Who Usually Conducts Analysis?	When is Analysis Usually Conducted?
BENEFIT: Avoided Ancillary Services			
▪ Resources that can start during blackout, ramp up quickly, or provide reactive power. ▪ Resources closer to loads.	▪ Usually smaller benefits than traditionally analyzed benefits . ▪ Market price data available for some services in some markets (e.g., PJM). ▪ Ancillary service savings from clean resources often site-specific and difficult to estimate. ▪ Separating ancillary service value from capacity value in long run analysis may be difficult.	▪ Utilities conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis.	▪ Resource planning and proceedings. ▪ Area-specific DSM program development.
BENEFIT: Wholesale Market Price Effects			
▪ All clean resources . ▪ Resources that operate during peak hours.	▪ Benefits depend on market/pricing structure and peaking resources and forecasted reserve margins. ▪ Actual market price data generally available. ▪ Studies to estimate benefits may be complex.	▪ ISOs and utilities conduct in-depth modeling. ▪ PUCs, other stakeholders review utility's results and/or conduct own analysis.	▪ Resource planning and proceedings. ▪ Area-specific DSM program development. ▪ Policy studies.
BENEFIT: Increased reliability and power quality			
▪ Distributed resources. ▪ Resources close to load or with high power quality. ▪ All resources that operate as baseload units. ▪ All load reducing resources that increase surplus generating and T&D capacity in region.	▪ Historical reliability data often available. ▪ Historical power quality data rare. ▪ Studies for converting to dollar value complex and controversial. ▪ Benefits are especially valuable for manufacturing processes that are sensitive to power quality or regions where reliability is significant concern.	▪ Utilities conduct in-depth modeling . ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis.	▪ Usually ad hoc studies.
BENEFIT: Avoided or reduced risks of overbuilding (associated with long lead-time investments, such as the risk of overbuilding the electric system)			
▪ Distributed resources with short lead times. ▪ Resources close to load ▪ All clean resources.	▪ Historical load and load variability data often available. ▪ Modeling varies from simple to complex.	▪ Utilities conduct in-depth modeling. ▪ PUCs and other stakeholders review utility's results and/or conduct own analysis. ▪ Policy and risk management analysts.	▪ Resource planning and regulatory review of planning. ▪ Policy studies.

TABLE 3.2.3 SECONDARY ELECTRIC SYSTEM BENEFITS FROM CLEAN ENERGY MEASURES *(cont.)*

Applicable Clean Energy Resources	Considerations for Determining Whether to Analyze	Who Usually Conducts Analysis?	When is Analysis Usually Conducted?
BENEFIT: Avoided or reduced risks of stranded costs (from deferring investment in traditional, centralized resources until environmental and climate change policies are implemented)			
▪ All clean energy resources.	▪ Modeling varies from simple to complex. ▪ Studies to estimate benefits may be complex. ▪ Regulatory uncertainty adds to complexity of analysis.	▪ Policy and risk management analysts.	▪ Resource planning and regulatory review of planning. ▪ Policy studies.
Fuel and technology diversification			
▪ All clean energy resources.	▪ Diversity metrics computable from generally available data ▪ Portfolio analysis of costs vs. risks adds complexity. ▪ Must consider existing supply resources, not just incremental new resources.	▪ States. ▪ PUCs. ▪ Utilities.	▪ State energy plans. ▪ Resource planning.

3.2.1 HOW TO ESTIMATE THE PRIMARY ELECTRIC SYSTEM BENEFITS OF CLEAN ENERGY RESOURCES

Implementing clean energy policies and programs results in reduced demand for electricity. As described earlier, the primary electric system benefits resulting from this reduced demand include:

- Avoided cost of energy generation or wholesale energy purchases,
- Avoided cost of power plant capacity,
- Deferred or avoided T&D capacity costs, and
- Avoided energy loss during T&D.

States can compare different electric resources, including clean energy resources such as energy efficiency, renewable energy, clean distributed generation, or combined heat and power, by examining the net present value of the revenue requirements over the life of the resource. This enables comparison of various options on an equal basis, combining capital investments—accounting for carrying costs over the book life of the investment—with the discounted value of their annual fuel and operating costs over the investment's operating life. For example, installing high-efficiency transformers in a new substation can be more expensive than standard equipment in terms of up-front costs, but will waste less electricity over time, thereby reducing variable operating and maintenance costs. Likewise, replacing a chiller in a food-processing factory with a more efficient unit incurs a higher capital cost up-front, but reduces annual electricity costs for the customer.[3] The basic concept is to compare the *net impact* on the cost of power over the lifetimes of each alternative that is technically capable of meeting the need. The alternative with the smallest net impact is typically the preferred choice, all other things being equal.

As indicated above, methods to quantify primary electric system benefits are mature and states can choose from a range of basic and sophisticated methods as described below.

[3] Some states have competition in retail electricity service, others do not, and some are in a transitional state. These examples apply to both traditional, vertically integrated utilities and to distribution-only utilities. However, the existence of retail competition changes some of the details in important ways. One such difference is that under retail competition, a portion of the cost savings from lowering electric consumption accrues to the distribution utility (e.g., reduced need to expand T&D lines) and a portion becomes a reduction in the revenues of competitive wholesale generators. The policy implications of that split need to be considered, but the important point is that the entire savings accrues to the retail customers and to society as a whole.

Basic Methods

Basic methods span a broad range of possibilities, but generally rely on relatively simple relationships and analytic structures. Many are conceptually similar to sophisticated methods, but they use simplifying assumptions (proxy plants, system averages) rather than using detailed models to develop the impacts or parameters to estimate impacts (e.g., emissions factors).

For example, in order to estimate impacts of a clean energy resource, the goal is to match impacts (in terms of reduced demand for electricity) to the generation resource that will be displaced. However, instead of running a dispatch model to make these estimates, simple proxies—for generating units displaced, or emissions rates at the time of displacement—are used instead. A dispatch model would identify specifically those units on the margin in each time period, but with a basic method it may be sufficient to pair impacts (i.e., changes in generation requirements due to energy efficiency or other clean energy resources) to the general type of unit expected to be on the margin. For example, for all impacts during the peak period, a natural-gas-fired combustion turbine could be used to estimate impacts. During baseload periods, a coal plant could be used; while in shoulder periods an oil/gas steam might be used. The details would depend on the system being analyzed.

Estimation methods can be used for preliminary assessments or screening exercises, such as comparing the cost of a clean energy option with a previous projection of avoided costs or the cost of a proxy plant. Proxy plant assessments are typically done using cost assumptions for the expected next addition; for example, a natural gas combined cycle plant. Although they are less robust than modeling methods, basic methods require less data, time, and resources, so they can be useful when time, budget, and data are limited.

Sophisticated Methods

State-of-the-art power sector models for simulating and projecting power plant operations and costs (or T&D system adequacy) represent one type of sophisticated model. The sophisticated models have more complex structures and interactions than the basic approaches, and are designed to capture fundamental behavior of the sector using engineering-economic relationships or econometric approaches. They require additional input assumptions compared with basic methods, but add the ability to evaluate how the operations and capacity needs of the existing electric grid will change with the adoption of a clean energy resource, based on engineering and economic fundamentals. Some models can predict energy prices, emissions, and other market conditions as well.

These models are complex to set up and can be costly. Developing a detailed representation of the electric system can involve many individual input assumptions, and it is important to validate, benchmark, or calibrate complex models against actual data. Access to confidential system data can also pose a challenge to conducting rigorous avoided cost analysis. However, in many cases datasets already exist for regional and utility planning analyses. Furthermore, existing sector models have the benefit of being well understood and mature.

While developing a full input data set for a dispatch simulation model can be a daunting task, it can provide a higher level of analytic rigor than basic estimation methods, which simplify complex systems and can result in errors in estimated costs. It is important to consider whether existing utility models can be relied on and are acceptable to stakeholders in a stakeholder process. If they can be relied on, the incremental work of estimating clean energy benefits will be greatly reduced.

Simulations of clean energy programs using sophisticated models can be done on an individual basis (e.g., modeling the impact of wind turbines) or the analysis can be used to assess multiple clean energy strategies. A single analysis of an affected system can provide a basis for analyses of a large number of clean energy programs simultaneously. For example, a sophisticated model may have the ability to assess the impact of an energy efficiency program and a renewable portfolio standard, capturing any interactions between the two. One of the benefits of more sophisticated approaches is their ability to capture these kinds of interactions.

The remainder of this section provides details about the methods available to assess the four primary electric systems benefits of clean energy.

3.2.1.a Avoided Costs of Electricity Generation or Wholesale Electricity Purchases

New clean energy resources (on the demand and supply side) avoid electricity and capacity costs in both the *short run* (e.g., three years or less) and in the *long run* (e.g., typically five to 20 years). In the short run, avoided costs consist of avoided fuel, variable operation and maintenance (O&M), and emissions allowances that can be saved at those generating units that would operate less frequently as a result of new clean energy resource additions. Methods to estimate these short-run avoided costs are described in this section.

In the long run, however, avoided costs consist largely of the capital and operating costs associated with new generation capacity and T&D capacity that are displaced or deferred by clean energy resources.[4] Methods to estimate these long-run costs are described in Section 3.2.1.b, *Avoided Costs of Power Plant Capacity,* and Section 3.2.1.c, *Avoided Transmission and Distribution Capacity*.

Key Considerations

A number of challenges arise when calculating short- and long-run avoided costs. Avoided cost estimates generally depend upon the comparison of two cases:

- A baseline or reference case without the new resource, and
- A case with the new resource, which in the case of a demand-side resource includes a reduction in the load or load decrement.

[4] *Sometimes the short-run and long-run effects of clean energy measures are referred to as "operating margin" and "build margin," respectively (Biewald, 2005).*

Short-run avoided costs of electricity generation are the operating costs of marginal units. Operating costs include fuel, variable O&M, and marginal emission costs. In a competitive market, wholesale energy prices will reflect the generator's actual costs for operating marginal units in the bids they submit.

Consequently, both cases involve projections of future conditions and are subject to many uncertainties that influence electricity markets (e.g., fuel prices, construction costs, environmental regulations, and market responsiveness to prices). Since avoided costs are calculated as the difference between these two cases, they can be very sensitive to the underlying assumptions for either or both cases. This uncertainty is characteristic of long-run avoided cost calculations which require projections far out into an uncertain future. Therefore, states may want to consider performing sensitivity or scenario analyses on both the underlying base case (e.g., on demand growth, fuel prices) and on the key drivers of the case with the new resources (e.g., on the cost or timing of new resources) to gauge the potential range of results.

TABLE 3.2.4 COMPARISON OF BASIC AND SOPHISTICATED APPROACHES FOR QUANTIFYING AVOIDED COST OF ELECTRICITY GENERATION OR WHOLESALE ELECTRICITY PURCHASES

Example	Advantages	Drawbacks	When to Use This Method
Basic Method			
▪ Proxy unit ▪ Futures prices ▪ Previously estimated cost projections	▪ Simple. ▪ May already be available.	▪ Combines energy & capacity. ▪ Not always relevant to a given policy if timing or costs are different. ▪ Limited horizon (futures). ▪ May miss interactive effects (fuel and emissions markets) and leakage effects for significant clean energy investments over time.	▪ When time, budget and data are limited. ▪ Rough estimates. ▪ Preliminary assessment. ▪ Overview-type policy assessment.
Sophisticated Method (Dispatch Modeling)			
▪ ProMod ▪ Market Analytics ▪ MAPS ▪ IPM	▪ Robust representation of electrical system dispatch.	▪ Cost. ▪ Data- and time-intensive. ▪ Not transparent.	▪ When clean energy resource use will change system operations (e.g., clean energy resources change the marginal generating resource in a large number of hours).

Methods for Estimating Short-Run Avoided Costs of Electricity Generation or Wholesale Electricity Purchases

Two types of methods for quantifying short-run avoided costs of electricity generation or wholesale electricity purchases—basic and sophisticated—are described below. Both have advantages and limitations that are dictated by individual circumstances (see Table 3.2.4), and involve these steps as presented in Figure 3.2.1.

1. *Estimate clean energy operating characteristics.* Using the total energy impacts estimates (as described in Chapter 2), estimate the load impact or energy generation profile of the clean energy measure—an estimate of when the energy would be available—either on an hourly basis, or some other more aggregate time scale.

2. *Identify the marginal units to be displaced.* Identify the generation resources that would be displaced as a result of the clean energy resource, either due to reduced demand or increased supply of clean energy.

3. *Identify the characteristics of the marginal units displaced.* This specifically includes the avoided energy costs (and as described later, avoided emissions).

4. *Map the energy impacts to the displaced unit information*. This is done to calculate the short-run avoided costs of electricity generation. For basic methods, the estimated energy impacts (reduction in load or energy supplied) are mapped to the displaced energy information. For example, if hourly impacts are estimated, hourly kWh savings are multiplied by hourly avoided costs estimates. The summation of these hourly values represents the impact of the clean energy resource on costs. For sophisticated methods, this calculation may be a direct output of the modeling exercise.

The various approaches are described further below.

Basic Methods for Estimating Short-Run Avoided Costs

Short-run avoided costs of energy generation can be estimated using simplified methods, such as spreadsheet analysis of market prices, marginal cost data, or inspection of regional dispatch information (i.e., fuel mix and capacity factor by fuel type). Non-modeling estimation methods, such as using a previously estimated avoided cost projection, may be more appropriate when time, budget, and access to data are limited, but they result in an approximation of the costs of avoided energy generation. Consequently, it is important for analysts to consider whether the estimation method is an acceptable representation of the actual system. For example, already-available avoided costs may be out of date or may not match the timing of the impacts of the clean energy resource being considered. The general steps involved in conducting these methods are described in more detail below.

Step 1: Estimate clean energy operating characteristics. The first part of estimating avoided costs of clean energy is to estimate the amount of energy (in kWh) the clean energy measure is expected to generate or save over the course of a year and its lifetime. Methods for estimating this were described in Chapter 2.

In addition to estimating annual impacts, it may be desirable to estimate the timing of impacts within a year, either hourly or on some less frequent interval. Clean energy resources that reduce generation requirements at the time of peak, when combustion turbines may be operating, will differ from those that affect the system during periods of low demand when oil/gas steam plants or coal plants may be operating.

In the case of energy efficiency measures, load impact profiles describe the hourly changes in end-use demand resulting from the program or measure. In the case of energy resources, the generation profiles (for wind or PV, for example) are required. The time period can range from 8,760 hourly intervals to two or three intervals, such as peak, off-peak, and shoulder periods. Similarly, a wind turbine can be expected to produce differing quantities of electricity across the day and year. These data are used to identify more precisely what specific generation or generation types are displaced by the clean energy resources.

Several sources are available to help predict the load profiles of different kinds of renewable energy and energy efficiency projects:

- Performance data for renewable technologies are available from the National Renewable Energy Laboratory (NREL), as well as universities and other organizations that promote or conduct research on the applications of renewable energy. For example, the Massachusetts Institute of Technology's Analysis Group for Regional Energy Alternatives

FIGURE 3.2.1 STEPS FOR ESTIMATING AVOIDED COST

STEP 1
Estimate Clean Energy Operating Characteristics

STEP 2
Identify the marginal units to be displaced

STEP 3
Identify the operating costs of marginal units to be displaced

STEP 4
Calculate the short-run avoided costs of electricity generation

and Laboratory For Energy and the Environment published a report in 2004 entitled Assessment of Emissions Reductions from Photovoltaic Power Systems (*http://web.mit.edu/agrea/docs/MIT-LFEE_2004-003a_ES.pdf*). Another useful source is the Connecticut Energy Conservation Management Board (*http://www.ctsavesenergy.org/ecmb/index.php*).

- The California Database for Energy Efficient Resources (DEER) provides estimates of energy and peak demand savings values, measure costs, and effective useful life of efficiency measures (*http://www.energy.ca.gov/deer/*).

- Some states or regions have technology production profiles in their efficiency and renewable energy potential studies (e.g., NYSERDA's report, Energy Efficiency and Renewable Energy Resource Development Potential in New York State, 2003, available at *http://www.nyserda.org/sep/EE&ERpotentialVolume1.pdf*).

- Load impact profile data for energy efficiency measures may be available for purchase from various vendors, but typically is not publicly available in any comprehensive manner.

- Wind profiles can be obtained from a number of sources, including the Department of Energy's NEMS model (*http://www.eia.doe.gov/oiaf/aeo/overview/*), NREL (*www.nrel.gov*), the American Wind Energy Association (*www.awea.org*), and several research organizations that have published information on wind resources in specific locations. All data will likely require some extrapolation or transposition for the intended use.

In the absence of specific data on the load impact or energy profile of the clean energy resource, analysts will need to use their judgment to assess the timing of that resource's impacts.

Step 2: Identify the marginal units to be displaced. The next step is to identify the units and their associated costs that are likely to be displaced by the clean energy resources. While this section discusses the process of estimating avoided cost benefits, these same methods support the estimation of emissions benefits of clean energy.

In each hour, electric generating resources are dispatched from least to most expensive, on a variable cost basis, until demand is satisfied. There are a host of complexities involved in dispatching the generating system, including generator start-up and shut-down operating constraints and costs, and transmission and reliability considerations, among other factors. However, in concept, the unit that is displaced is the last unit to be dispatched. Estimating the benefits of clean energy resources requires identifying this "marginal" unit and its avoided costs. Because reported or modeled avoided costs may not reflect some of the other complexities identified above, simply looking at variable fuel and O&M may be misleading. However, basic approaches using system averages, time-dependent methods, displacement curves, and load dispatch curve analysis can give reasonable estimates of the impacts of clean energy.

System Averages

The simplest approach to estimating the impacts of the displaced unit, absent any detailed information on the system, is to use the average generating unit as a proxy. Some studies have used this approach. The average system costs and the average emissions characteristics can be used to estimate impacts; however, most analysts recognize that some types of generating units are almost never on the margin and therefore should not be included in the characterization of the marginal unit. For example, nuclear units, hydropower, and renewable resources are very rarely on the margin and unlikely to be displaced by clean energy sources in the short run. Moreover, the average cost of generation can differ greatly from the marginal source of generation.

In response to this observation, one approach sometimes used is to characterize the remaining units—specifically, the fossil units—as a representation of the average marginal unit. This is an improvement over the system average, but still does not capture the potential impact of a variety of clean energy resources, each with differing impact patterns. For example, in many regions of the country coal units are on the margin only a small number of hours during the year. Thus, using a fossil average may understate cost savings and overstate emissions impacts of the clean energy resource. Despite these limitations, absent any detailed information on the impact of the resource or the nature of the marginal generation, this approach is an option.

Time Dependent Methods

Another method to estimate the impacts of clean energy resources, including effects on costs and emissions, is to identify those resources that are expected to be displaced depending on the time the clean energy impacts occur. The most detailed approach is to identify the marginal generating unit on an hourly basis. Clean energy impacts (in kWh) can then be mapped (using the time of impact estimates described above) to the appropriate marginal generation source. Costs savings (and emissions impacts) can then be estimated.

Time-dependent methods do not need to be on an hourly basis; several less data-intensive basic approaches (displacement curves and load curve analysis) are available and described below:

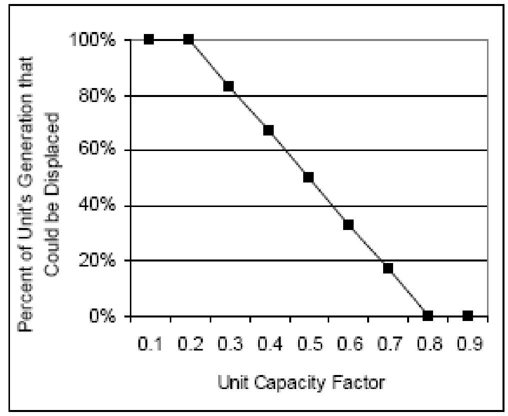
Displacement Curves

Another approach to estimating what will be displaced by clean energy involves displacement curves. Baseload plants operate all of the time throughout the year because their operating costs are low and because they are typically not suitable for responding to the many fluctuations in load that occur throughout the day. As a result, they would not be expected to be displaced with any frequency. These plants would have high capacity factors (e.g., greater than 0.8). Capacity factor is the ratio of how much electricity a plant produces to how much it could produce, running at full capacity, over a given time period. *Load-following* plants, in contrast to baseload plants, can quickly change output, have much lower capacity factors (e.g., less than 0.3) and are more likely to be displaced.

A displacement curve can be developed to identify what generation is likely to be displaced. The curve would reflect the likelihood of a unit being displaced,

FIGURE 3.2.2 DISPLACEMENT CURVE BASED ON CAPACITY FACTOR

Sample curve for relating displacement to capacity factor



Source: Keith and Biewald, 2005.

based on a proxy for its place in the dispatch order. A reasonable proxy for the likelihood of a generating unit to be displaced by a clean energy measure is the unit's capacity factor. Figure 3.2.2 illustrates this concept using capacity factor as a proxy. Baseload plants on the right side of the curve, such as nuclear units, are assumed to be very unlikely to be displaced; peak load plants on the left, such as combustion turbines, are much more likely to be displaced. These capacity factor estimates can be based on an analysis of actual dispatch data, modeling results, or judgment. Historic data on, or estimates of, capacity factors for individual plants are available from EPA's eGRID database (*http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html*).

It is important to note that a displacement curve may not capture some aspects of electric system operations. For example, an extended outage at a baseload unit (for scheduled maintenance or unanticipated repairs) would increase the use of load-following and peaking units, affecting the change in net emissions from the clean energy project. According to the displacement curve, this plant would be more likely to be displaced, even though it would rarely if ever be on the margin. The relationship between capacity factor and percent of time it will be displaced could be determined analytically (e.g., examining historical data on the relationship between a unit's capacity factor and the time it is on the margin. More likely a judgment could be made about this relationship. Other proxies could serve to develop this curve, including unit type (e.g., coal steam, nuclear, combustion turbine), heat rate, or pollution control equipment in place.

Load Curve Analysis

In general, generating units are dispatched in a predictable order that reflects the demand on the system and the cost and operational characteristics of each unit. These plant data can be assembled into a generation "stack," with lowest marginal cost units on the bottom and highest on the top. A dispatch curve analysis matches each load level with the corresponding marginal supply (or type of marginal supply). Table 3.2.5, *Hypothetical Load for One-Week Period*, and Figure 3.2.3, a hypothetical dispatch curve representing 168 hours by generation unit, ranked by load level, provide a combined example of a dispatch curve that represents 168 hours (a one-week period) during which a hypothetical clean energy resource would be operating.

Table 3.2.5 illustrates this process for a one-week period. There are 10 generating units in this hypothetical power system, labeled 1 through 10. Column [3] shows the number of hours that each unit is on the margin.

In many cases, dispatch curves are available from the local power authorities and Load Balancing Authorities [e.g., a regional Independent System Operator (ISO)]. If this information is not available, states can attempt to construct their own analysis.

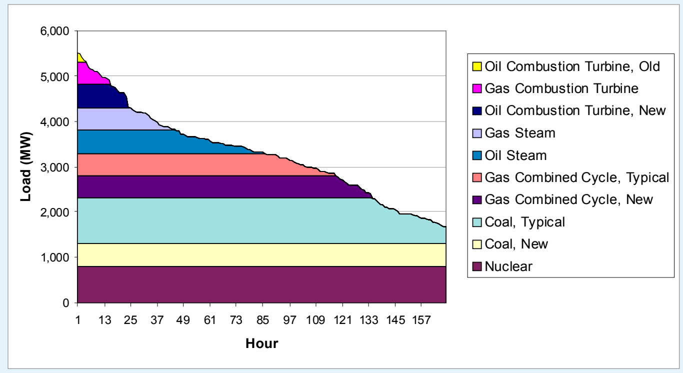
Constructing a dispatch curve requires data on:

- Historical utilization of all generating units in the region of interest;
- Operating costs and emission rates (to support emissions estimation, as described in Chapter 4) of the specific generating units, for the most disaggregate time frame available (e.g., seasonally, monthly);
- Energy transfers between the control areas of the region and outside the region of interest (because the marginal resource may be coming from outside the region); and
- Hourly regional loads.

Operating cost and historical utilization data can typically be obtained from the EIA (*http://www.eia.doe.gov/cneaf/electricity/page/data.html*) or the local Load Balancing Authority.[5] When generator cost data

[5] *Often these sources can also provide generator-specific emission rates for estimating potential emission reductions from clean energy.*

FIGURE 3.2.3 A HYPOTHETICAL LOAD DURATION/DISPATCH CURVE REPRESENTING 168 HOURS (shown in half-day increments) by generation unit, ranked by load level



Source: Developed by Synapse Energy, unpublished, 2007.

TABLE 3.2.5 HYPOTHETICAL LOAD FOR ONE-WEEK PERIOD: HOURS ON MARGIN AND EMISSION RATE

[1]	[2]	[3]
Unit	Unit name	Hours on margin
1	Oil Combustion Turbine, Old	5
2	Gas Combustion Turbine	10
3	Oil Combustion Turbine, New	9
4	Gas Steam	21
5	Oil Steam	40
6	Gas Combined Cycle, Typical	32
7	Gas Combined Cycle, New	17
8	Coal, Typical	34
9	Coal, New	0
10	Nuclear	0
Weighted average, SO2 emissions (lbs/MWh): 5.59		

are not available, capacity factors (from the eGRID database, for example, as described above) for traditional generating units can be used to approximate the relative cost of the unit (those with the highest capacity factors are assumed to have the lowest cost). As an exception, variable power resources such as wind and hydropower are assumed to have lower costs than fossil fuel or nuclear units.

Operational data (or simplifying assumptions) regarding energy transfers between the control areas of the region and hourly regional loads can be obtained from the ISO or other Load Balancing Authority within the state's region.

Dispatch curve analysis is commonly used in planning and regulatory studies. It has the advantage of incorporating elements of how generation is actually dispatched while retaining the simplicity and transparency associated with non-modeling methods. However, this method can become labor-intensive relative to other non-modeling methods for estimating displaced emissions if data for constructing the dispatch curve are not readily available. Another disadvantage is that it is based on the assumption that only one unit will be on the margin at any given time; this generally is not true in most regions.

Methods described earlier, such as displacement curves, can support the development of a simplified dispatch curve. For example, capacity factors can be used to "fill" the horizontal segments on the curve as shown in Figure 3.2.3. One can assume that units with capacity factors greater than 80 percent can fill the baseload segments and that peaking units, with the lowest capacity factors, would fill the peak segments. Units with capacity factors between 80 and 60 percent would fill the next slice of the dispatch curve, and so on. The resolution would reflect available data or the ability to develop meaningful assumptions. The hope is that the level of aggregation is such that the units' characteristics are generally similar and as such the marginal unit would be approximated by the group average. If data allows, it is possible to take into account differences in units that drive their costs and emissions (e.g., general unit type and burner type, the presence of pollution control equipment, unit size, fuel type).

Step 3: Identify the operating costs of marginal units to be displaced. This process varies depending on whether the market is regulated or restructured.

In regulated markets, short-run avoided energy costs typically include fuel costs, a variable O&M cost, and marginal emissions costs for the highest-cost generator in a given hour. Data sources for control area hourly marginal costs include the U.S. Federal Regulatory Commission (FERC) form 714 (***http://www.ferc.gov/docs-filing/eforms/form-714/overview.asp***).

In restructured markets, where RTOs administer regional wholesale power markets, economic dispatch is conducted on the basis of bid prices rather than generators' marginal costs (theoretically equivalent to the marginal cost). This information is available at each ISO's Web site (see *Information Resources* at the end of this chapter for the Web sites of individual ISOs).

For longer-term analysis it is necessary to forecast cost increases. Historical hourly operating costs for the marginal unit (i.e., regulated markets) or market prices (i.e., restructured markets) can be escalated using forward market electricity prices, though the forecast time frame is limited. Forward electricity prices are available from energy traders and industry journals such as Platt's MegaWatt Daily (***http://www.platts.com/Electric%20Power/Newsletters%20&%20/Megawatt%20Daily/***).

Step 4: Calculate the short-run avoided costs of electricity generation. For each hour or time of use period, multiply the cost of the marginal unit or hourly energy market price by the reduction in load (for demand-side resources) or the increase in generation (for supply-side resources), as estimated using techniques described in Chapter 2. Typically, avoided costs are expressed as the annual sum of these avoided costs for each hour or other time period.

The *Estimating Short-Run Avoided Cost* text box illustrates how all four steps can be used to estimate short-run avoided costs.

Key Considerations

These basic methods have some limitations that should be considered when choosing an approach:

- Methods that rely on historical data are limited to replicating what occurred in the past. Substantial changes in costs or performance of generation, or other restrictions on their operations (e.g., climate legislation, requirements for a renewable portfolio standard) could fundamentally change the operation of the system and the implied dispatch curve.

Estimating Short-Run Avoided Cost

To illustrate the described approach for estimating short-run avoided costs, consider the case of a state that wishes to evaluate the potential benefits of an energy efficiency program. Sample calculations are illustrated in the accompanying table.

Step 1: The state estimates that the energy efficiency program would reduce electricity demand as shown in the *Avoided Electricity* column (based on an analysis of annual savings from the typical system and a typical load shape).

Step 2: Using a load curve analysis, the state estimates that natural gas combustion turbines are typically on the margin during peak periods for both summer and winter, a mix of natural gas combined cycle units and natural gas-fired steam units (about 50% of each) are on the margin during shoulder periods, and existing coal-fired generators (pulverized coal) are typically on the margin during the off-peak periods.

SAMPLE CALCULATION OF SHORT-RUN ENERGY AVOIDED COSTS

Time Period	Avoided Electricity (MWh)	Avoided Energy Cost for Time Period ($/kWh)	Total Avoided Energy Cost ($)
Summer Peak (912 hours)	123,120	0.08	9,234,000
Summer Shoulder (1368 hours)	153,900	0.06	8,772,300
Summer Off-Peak (1368 hours)	20,520	0.03	513,000
Winter Peak (1278 hours)	115,020	0.07	8,051,400
Winter Shoulder (1917 hours)	143,775	0.06	8,195,175
Winter Off-Peak (1917 hours)	19,170	0.03	479,250
Total	575,505		35,245,125

Step 3: The avoided costs associated with each of these marginal generating technologies are estimated based on typical variable operating and fuel costs for those types of units estimated to be on the margin. The results are show in the *Avoided Energy Cost for Time Period* column.

Step 4: The *Total Avoided Energy Cost* column shows the result of multiplying the *Avoided Electricity* column by the *Avoided Energy Cost for Time Period* column. Summing across all periods yields the expected avoided costs for one year.

  - Even without such fundamental changes, the system changes over time as new units are added, existing units are retired, and units shift in dispatch order. Analyses based on historical data do not capture these shifts, so to the extent that estimates are being developed for the future these types of basic methods must be used with caution.

- These methods may not adequately address the issue of leakage—in which increases in clean energy result in reductions in generation outside the region of interest (e.g., in another state or region)—if these transactions are not explicitly accounted for in the analysis.

Sophisticated Methods for Estimating Short-Run Avoided Costs: Dispatch Modeling

Sophisticated simulation modeling, such as electric dispatch modeling, requires developing a detailed representation of the electric system with many individual input assumptions. While developing a full input data set for a dispatch simulation model can be a resource-intensive task, the output from a simulation model can provide more valid estimates than a basic approach, especially for clean energy resources with more availability at certain times and for projections of clean energy impacts in the future. Dispatch models can also be employed to develop parameters that can be used to estimate the impacts of a large range of clean energy resources. For example, multiple model runs can be performed estimating impacts of changes in generation requirements at certain seasons and times of day (e.g., winter peak, summer peak, winter base, etc.). These parameters, such as the marginal emission rate and avoided costs, can be applied to estimates of the impacts of clean energy resources at those same times.

Dispatch models simulate the dynamic operation of the electric system given the characteristics of specific generating units and system transmission constraints. They typically do not predict how the electric system will evolve but instead can indicate how the existing electric sector will respond to a particular clean energy policy or measure. This is appropriate in the short run when the electric system is more likely to react than to evolve due to clean energy measures. Dispatch models specifically replicate least-cost system dispatch and can be used to determine which generating units are dis-

NEW YORK ENERGY $MART℠ PROGRAM COST EFFECTIVENESS ASSESSMENT

The New York State Energy Research and Development Authority (NYSERDA) periodically evaluates the cost-effectiveness (using a benefit-cost ratio) of New York Energy $mart energy efficiency programs. NYSERDA uses a production costing model, MAPS, to forecast the avoided energy and capacity benefits of the programs for several years. Avoided energy costs are forecasted by applying MAPS escalation rates to the weighted average energy price by location and time period. The weighted average energy prices are based on historical hourly NYISO day-ahead market data for January 2000 through December 2004. The avoided capacity costs are forecasted by applying the same escalation rates to NYISO monthly capacity data by location and time period.

Source: Heschong Mahone Group, Inc., 2005.

placed and when they are displaced based on economic and operating constraints.

Hourly dispatch modeling is generally used for near-term, highly detailed estimations. This approach is appropriate for financial evaluations of specific projects, short-term planning, and regulatory proceedings. Sensitivity cases can be run to explore the range of possible impact values. While this type of modeling is generally seen as very credible in these contexts, it often lacks transparency. For example, dispatch models vary in terms of how they treat outage rates, heat rates, bidding strategies, transmission constraints, and reserve margins. Underlying assumptions about these factors may not be apparent to the user. Moreover, labor and data needs are extensive. Software license and labor costs can be prohibitively high for many agencies and stakeholders, who often must rely on the results of dispatch modeling conducted by utilities and their consultants for regulatory proceedings.

Generally, this method involves modeling electricity dispatch with and without the new resource, on an hourly basis, for one to three years into the future. As with basic estimation methods, it is essential to establish the specific operational profile of the clean energy resource. Alternatively, an hourly dispatch model can be used to determine hourly marginal costs and emission rates (lbs/kWh), which can then be aggregated by time period and applied to a range of clean energy resources according to their production characteristics. Some models, described later in this chapter, simulate both capacity planning and dispatch, although they may have a simpler representation of dispatch (e.g., seasonally, with multiple load segments). These models are applied similarly to models that strictly address dispatch, but offer the ability to capture the differing marginal resources over load levels and time.

Tools

There are several dispatch models available for states to use:

- *EnerPrise Market Analytics* (powered by PROSYM) supported by Ventyx®.

  A chronological electric power production costing simulation computer software package, PROSYM is designed for performing planning and operational studies. As a result of its chronological nature, PROSYM accommodates detailed hour-by-hour investigation of the operations of electric utilities. Inputs into the model are fuel costs, variable operation and maintenance costs, and startup costs. Output is available by regions, by plants, and by plant types. The model includes a pollution emission subroutine that estimates emissions with each scenario. ***http://www1.ventyx.com/analytics/market-analytics.asp***

- *Multi-Area Production Simulation (MAPS™)* developed and supported by GE Energy and supported by other contractors.

  A chronological model that contains detailed representation of generation and transmission systems, MAPS can be used to study the impact on total system emissions that result from the addition of new generation. MAPS software integrates highly detailed representations of a system's load, generation, and transmission into a single simulation. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation. ***http://www.gepower.com/prod_serv/products/utility_software/en/ge_maps/index.htm***

- *Plexos for Power Systems™* owned by Energy Exemplar.

  A simulation tool that uses LP/MIP (Linear Programming/Mixed Integer Programming) optimization technology to analyze the power market, Plexos contains production cost and emissions modeling, transmission modeling, pricing modeling, and competitiveness modeling. The tool can be used to evaluate a single plant or the entire power system. ***http://www.energyexemplar.com***

- *PowerBase Suite*™ (including PROMOD IV®) supported by Ventyx.

  A detailed generator and portfolio modeling system, with nodal locational marginal pricing forecasting and transmission analysis, PROMOD IV can incorporate extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operation conditions, and market system operations. ***http://www1.ventyx.com/analytics/promod.asp***

3.2.1.b Avoided Costs of Power Plant Capacity

While the avoided cost of energy generation is the major short-run benefit, avoided costs of power plant capacity in the long run can be significant and should be included in resource decisions.[6] For example, in the short run, surplus centralized generation capacity that is freed up by clean energy policies and programs can be sold to other utilities in the region for meeting their capacity needs. These costs are based on the levelized[7] capital costs of peaking capacity (e.g., a combustion turbine) or on the market price for peaking capacity. This is a critical factor in competitive wholesale markets. Over the long run, however, new clean energy initiatives typically avoid or defer both the cost of building new power plants and the cost of operating them. These are the avoided costs of power plant capacity that can be estimated using either basic estimation or sophisticated simulation approaches.[8] Both have advantages and limitations, as described in Table 3.2.6.

Basic Methods for Estimating Avoided Costs of Power Plant Capacity

Basic estimation methods involve the use of tools such as spreadsheets to estimate any long-run avoided costs of power plant capacity that may result due to a clean energy measure under consideration. One method commonly used is the proxy plant approach. This approach involves estimating the avoided cost of a power plant that might be built in the future. Energy cost estimates (as described above) would reflect this plant's dispatch costs for future estimates and the capital costs. Depending on future expectations of capital costs, fuel prices, and environmental requirements, either a

6 *For more information about establishing energy efficiency as a high priority resource in long run planning, see National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change, November 2008.* ***http://www.epa.gov/cleanenergy/energy-programs/napee/resources/vision2025.html***.

7 *The present value of capital costs, levelized in real dollars to remove the effect of inflation.*

8 *For information about how utilities estimate avoided costs, see The Guide to Resource Planning with Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency, November 2007,* ***www.epa.gov/cleanenergy/documents/resource_planning.pdf****, or Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities (Tellus Institute, 1995).*

TABLE 3.2.6. COMPARISON OF BASIC AND SOPHISTICATED APPROACHES FOR QUANTIFYING AVOIDED COSTS OF POWER PLANT CAPACITY

Example	Advantages	Drawbacks	When To Use This Method
Basic approach			
▪ Peaker construction cost. ▪ See also above for combined capacity & energy estimate.	▪ Simple. ▪ May already be available.	▪ Peaker methodology does not reflect opportunities to displace baseload in the long run.	▪ Rough estimates. ▪ Preliminary screening of demand response resources. ▪ Overview-type policy assessments.
Sophisticated approach			
▪ Capacity Expansion/Ventyx. ▪ *PowerBase Suite*. ▪ *IPM*.	▪ Robust representation of electrical system operation.	▪ Cost. ▪ Data- and time-intensive. ▪ Not transparent.	▪ When clean energy resource use will change system operations (e.g., clean energy resources change the marginal generating resource in a large number of hours).

ELECTRIC ENERGY EFFICIENCY AND RENEWABLE ENERGY IN NEW ENGLAND: THE OTC WORKBOOK

An analysis conducted by the Regulatory Assistance Project (RAP) explains how energy efficiency and renewable energy have led to many positive effects on the general economy, the environment, and energy security in New England while also quantifying these effects in several new ways. The report assesses the air quality effects of efficiency and renewable investments using the OTC Workbook tool. The analysis finds that there is clear progress in reducing CO2 emissions from the deployment of energy efficiency and renewable energy. The projections by the OTC Workbook indicate that due to current energy efficiency programs, 22.5 million tons of CO2 emissions are avoided from 2000–2010.

Source: The Regulatory Assistance Project. http://www.raponline.org/Pubs/RSWS-EEandREinNE.pdf

A RESOURCE FOR CALCULATED AVOIDED EMISSIONS: THE MODEL ENERGY EFFICIENCY PROGRAM IMPACT EVALUATION GUIDE

The Model Energy Efficiency Program Impact Evaluation Guide provides guidance on model approaches for calculating energy, demand, and emissions savings resulting from energy efficiency programs. The Guide is provided to assist in the implementation of the National Action Plan for Energy Efficiency's five key policy recommendations and its Vision of achieving all cost-effective energy efficiency by 2025. Chapter 6 of the report presents several methods for calculating both direct onsite avoided emissions and reductions from grid-connected electric generating units. The chapter also discusses considerations for selecting a calculation approach (NAPEE, 2007).

combined cycle combustion turbine or a new advanced coal plant may be used as the proxy plant to represent the long-run avoided costs of energy and capacity of clean energy initiatives.

Data required for this method include:

- Cost and performance information for the proxy plant; and
- Capital cost escalation rates, a discount rate, and other financial data.

Utilities are one possible source of these data and often provide this information to public utility commissions in resource planning and plant acquisition proceedings. Other data sources include:

- *Regional transmission organizations, independent system operators, and power pools.* These sources maintain supply and demand projections by region and often sub-region.
- *The U.S. Energy Information Administration (EIA) Annual Energy Outlook*. This resource provides long-term projections of fuel prices and electricity supply and demand. In addition, some states and regions develop their own forecasts of electricity demand, fuel prices, and other variables. ***http://www.eia.doe.gov/oiaf/aeo/***
- *Regional reliability organizations*. These organizations can provide information on required reserve margins.
- *The Bureau of Economic Analysis (BEA)*. The BEA provides information on economic forecasts. The BEA releases measures of inflation (e.g., the Gross Domestic Product Implicit Price Deflator), which are available on its Web site ***http://www.bea.gov/national/index.htm#gdp***
- *The Securities and Exchange Commission (SEC) and the Federal Energy Regulatory Commission (FERC)*. Individual utility historical financial data are available in annual reports and other utility filings with the SEC and FERC. Utilities file annual 10-K and quarterly 10-Q company reports with the SEC. These data are available from the SEC EDGAR system at ***http://www.sec.gov/edgar.shtml***. Utilities also file FERC Form 1, which is available from FERC at ***http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp***. They can also be retrieved from the eLibrary at ***http://www.ferc.gov/docs-filing/elibrary.asp***.

Using data on initial construction costs, fixed and variable operating costs, and financial data, a discounted cash flow analysis can be conducted. Once estimated, the net present value of the cost of owning the unit that reflects the full carrying costs of the new unit (including interest during construction, debt servicing, property taxes, insurance, depreciation, and return to equity holders) can be converted to annualized costs (in $/kW-year). The annual capital costs ($/kW-year) can be multiplied by the annual capacity savings from the technology to estimate the avoided capital costs. The load profile information (reductions in demand at peak hours), discussed earlier would provide an estimate of displaced capacity, or simpler estimates can be used.

Sophisticated Methods for Estimating Avoided Costs of Power Plant Capacity: Capacity Expansion Models

Sophisticated simulation methods, such as capacity expansion models (also called system planning models), can be used to quantify the long-run avoided capacity costs that result from implementing clean energy measures. Capacity expansion models predict how the electric system will evolve over time, including what capacity will be added through the construction of new generating units and what units will be retired, in response to changes in demand and prices. This method involves allowing the model to predict what will likely happen to the resource mix based on costs of new technology, growth, existing fleet of generating assets, environmental regulations (current and planned), and considering dispatch both with and without the new clean energy resource. Capacity expansion models are typically used for longer-term studies (e.g., five to 20 years), where the impacts are dominated by long-term investment and retirement decisions. They are also typically used to evaluate large geographic areas.

Using capacity expansion models to estimate the avoided costs of power plant capacity typically involves the steps described below.

Step 1: Generate a business-as-usual forecast of load and how it will be met. Some capacity expansion models use existing generating plants and purchase contracts to serve the load over the forecast period, and the model (or the modeler) adds new generic plants when those resources do not meet the load forecast. The type of plants added depends on their capital and operating costs, as well as the daily and seasonal time-pattern of the need for power determined using discounted cash flow analysis as described earlier. The model repeats this process until the load is served through the end of the forecast period and a least-cost solution is found. This base case contains a detailed schedule of resource additions that becomes the benchmark capital and operating costs over the planning period for later use in the long-run avoided cost calculation.

Step 2: Include the clean energy resource over the planning period and create an alternate forecast. The following two approaches can be used to incorporate the clean energy resource into the second projection:

- For a more precise estimate of the savings from a clean energy program, reduce the load forecast year by year and hour by hour to capture the impact of energy efficiency resources, based on the program design and estimates of its energy and capacity savings, or add renewable resources as an available supply. This method would capture the unique load shape of the clean energy resource.
- For a less rigorous estimate (e.g., to use in screening candidate clean energy policies and programs during program design), reduce the load forecast by a fixed amount in each year, proportionally to load level. This method does not capture the unique load shape or generation supply of the clean energy resource.
- For renewable resources, add the resource to the supply mix (or for some models and non-dispatchable resources, renewable energy could be netted from load in the same manner as is done for energy efficiency).

In both the precise and less rigorous methods described above, the difference in the projected capital and operating cost over the planning period of the two cases is the avoided capacity cost to use in analyzing the clean energy resource. If a per unit avoided cost, such as the avoided cost per MWh, is needed for screening clean energy resources or other purposes, it may be computed by taking the avoided cost (i.e., the difference between the cost in the two cases) for the relevant time period (e.g., a given year) and dividing that by the difference in load between the two cases.

Step 3: Calculate the avoided costs of power plant capacity. The difference between the costs in the two projections above represents the annualized or net present value costs that would be avoided by the clean energy resource.

Capacity expansion or system planning models can examine potential long-term impacts on the electric sector or upon the entire energy system—in contrast to the dispatch models used to assess the avoided costs

Capacity Expansion Modeling involves three steps:

1. Generate a BAU forecast of load, and how load will be met without the clean energy resources;
2. Create an alternate forecast that includes the clean energy resources over the planning period to show how load is expected to be met.
3. Calculate the avoided costs of power plant capacity.

of energy generation, which focus on only the electric sector. Capacity expansion models that can examine the potential impacts of programs upon the entire energy system are generally used for projecting scenarios of how the energy system will adapt to changes in supply and demand or to new policies including emissions controls. They take into account the complex interactions and feedbacks that occur within the entire energy system (e.g., fuels and emissions markets), rather than focusing solely upon the electric sector impacts. This is important because there are tradeoffs at the system level in the technological and economic feasibility of fuels and technologies that may not be captured by a model that focuses solely on a particular aspect of the electric system. In addition to capturing the numerous interactions, energy system capacity expansion models can also model dispatch, although often not in a chronologic, 8760-hour dispatch.[9]

Tools: Electric Sector-only Capacity Expansion Models

Commonly used electric sector-only capacity expansion models for calculating long-run avoided costs of power plant capacity include:

- *IPM®* developed and supported by ICF International.

  This model simultaneously models electric power, fuel, and environmental markets associated with electric production. It is a capacity expansion and system dispatch model. Dispatch is based on seasonal, segmented load duration curves, as defined by the user. IPM also has the capability to model environmental market mechanisms such as emission caps, trading, and banking. System dispatch and boiler and fuel-specific emission factors determine projected emissions. IPM can be used to model the impacts of clean energy resources on the electric sector in the short and long term. ***http://www.icfi.com/Markets/Energy/energy-modeling.asp#2***

- *PowerBase Suite* (including Strategist®) supported by Ventyx.

  Strategist is composed of multiple application modules incorporating all aspects of utility planning and operations. This includes forecasted load modeling; marketing and conservation programs; production cost calculations including the dispatch of energy resources; optimization of future decisions; non-production-related cost recovery (e.g., construction expenditures, AFUDC, and property taxes); full pro-forma financial statements; and rate design. ***http://www1.ventyx.com/analytics/strategist.asp***

Tools: Whole Energy–Economy System Planning Models

Energy system-wide models with electricity sector capacity expansion capability include:

- *U.S. DOE National Energy Modeling System (NEMS)* is a system-wide energy model that represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions, by solving for the prices of each energy product that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior. The Electric Market Model, a module within NEMS, forecasts the actions of the electric power sector over a 25 year time frame and is an optimization framework. NEMS is used to produce the Energy Information Administration's Annual Energy Outlook, which projects the U.S. energy system through 2030 and is used as a benchmark against which other energy models are assessed. ***http://www.eia.doe.gov/oiaf/aeo/overview/***

- *MARKet ALlocation (MARKAL) Model* was created by the DOE Brookhaven National Laboratory in the late 1970s, and is now supported by a large international users group. MARKAL quantifies the system-wide effects of changes in resource supply and use, technology availability, and environmental policy. The MARKAL model determines the least-cost pattern of technology investment and utilization required to meet specified demands and constraints, and tracks the resulting changes in criteria pollutant and CO_2 emissions. This model is a generic framework that is tailored to a particular application through the development of energy system-specific data. MARKAL databases have been developed by various groups for national, regional, and even metropolitan-scale applications. For example, EPA has developed national and Census-division level databases (***http://www.epa.gov/appcdwww/apb/globalchange/markal.htm***).

[9] *For more information about using capacity expansion models to estimate air and GHG emissions from clean energy initiatives, please see Section 4.2.2, Step 2: Quantify Air and GHG Emission Reductions from Clean Energy Measures.*

MARKAL requires seconds to an hour to run on a desktop computer, depending on the size of the database and the options selected. ***http://www.etsap.org/markal/main.html***

- *Energy 2020* is a simulation model that includes all fuel, demand, and supply sectors and simulates energy consumers and suppliers. This model can be used to capture the economic, energy, and environmental impacts of national, regional or state policies. Energy 2020 models the impacts of a clean energy measure on the entire energy system. User inputs include new technologies and economic activities such as tax breaks, rebates, and subsidies. Energy 2020 uses emission rates for NO_X, CO_2, SO_2, and PM for nine plant types included in the model. It is available at the national, regional and state levels. ***http://www.energy2020.com/***

Key Considerations

While capacity expansion or system planning modeling is generally seen as very credible in long-run contexts, it:

- is more resource-intensive than the estimation methods and
- often lacks transparency due to its complexity and proprietary nature.

It is important to carefully consider key assumptions, such as fuel price forecasts and retirements, and the ability to accurately model the complex factors affecting the system including environmental and other regulatory requirements (e.g., renewable portfolio standards).

These assumptions point to the need for model validation or calibration against actual data or another projection model.

Most of the models are supported by their developers or other consultants who have available data sets. Some studies calibrate against the NEMS-generated Annual Energy Outlook produced by DOE's Energy Information Administration.

3.2.1.c Avoided Transmission and Distribution Capacity Costs

Clean energy policies and programs—such as customer-sited renewables and clean DG, including CHP—that are sited on or near a constrained portion of the T&D system, can potentially:

- Avoid or delay costly T&D upgrades, construction, and associated O&M costs, including cost of capital, taxes and insurance; and
- Reduce the frequency of maintenance, because frequent peak loads at or near design capacity will reduce the life of some types of T&D equipment.

Deferral of T&D investments can have significant economic value. The value of the deferral is calculated by looking at the present value difference in costs between the transmission project as originally scheduled and the deferred project. Most often, the deferred project will have a slightly higher cost due to inflation and cost escalations (e.g., in raw materials), but can have a lower present value cost when the utility discount rate is considered (which affects the utility's cost of capital). The difference in these two factors determines the value of deferring the project.

The avoided costs of T&D capacity vary considerably across a state depending on geographic region and other factors. Figure 3.2.4, *California T&D Avoided Costs by Planning Area in 2003,* was developed for the California Public Utilities Commission in 2003. It illustrates how avoided costs of T&D capacity vary in California (in $/kW-year) by planning area, utility, climate zone, and time of day. Using avoided cost estimates based on these differences, rather than on statewide system averages, enables states to better target the design, funding, and marketing of their clean energy actions (E3 and RMI, 2004; Baskette et al., 2006).

The benefit of avoided T&D costs is often overlooked or addressed qualitatively in resource planning, because estimating the magnitude of these costs is typically more challenging than estimating the avoided costs of energy generation and plant capacity. For example, the avoided T&D investment costs resulting from a clean energy program are highly location-specific and depend on many factors, including the current system status, the program's geographical distribution, and trends in customer load growth and load patterns. It is also difficult to estimate the extent to which clean energy measures would avoid or delay expensive T&D upgrades, reduce maintenance, and/or postpone system-wide upgrades, due to the complexity of the system.

FIGURE 3.2.4 CALIFORNIA T&D AVOIDED COSTS BY PLANNING AREA IN 2003

Source: Baskette et al., 2006.

The most appropriate approach for estimating avoided T&D costs is the *system planning approach*.[10] The system planning approach uses projections and thus can consider future developments, whether conducted via a modeling or non-modeling approach. Generally, it is difficult to be precise when calculating the avoided cost of T&D capacity because these costs are very site-specific and their quantification involves detailed engineering and load flow analyses.

The system planning approach uses projected costs and projected load growth for specific T&D projects based on the results from a system planning study—a rigorous engineering study of the electric system to identify site-specific system upgrade needs. Other data requirements include site-specific investment and load data. This approach assesses the difference between the present value of the original T&D investment projects and the present value of deferred T&D projects.[11]

Another factor affecting location-specific T&D project cost estimates is system congestion and reliability. During periods of high congestion, interconnected resources that can be dispatched at these specific times are credited at time-differentiated avoided costs. This approach is used by the California PUC to estimate long-term avoided costs to support analyses of the cost-effectiveness of energy efficiency measures. [See Section 3.5, *Case Studies* (E3 and RMI, 2004)]. Reliability considerations are reflected in avoided cost calculations through consideration of the Loss of Load Probability (LOLP), which is an indicator of the probability of failure to serve loads (NARUC, 1992).[12]

Tools

Specialized proprietary models of the T&D system's operation may be used to identify the location and timing of system stresses. Examples of such models include the following:

PowerWorld Corporation offers an interactive power systems simulation package designed to simulate high voltage power systems operation on a variable time frame. ***http://www.powerworld.com/***

Siemens (PSS®E) offers probabilistic analyses and dynamics modeling capabilities for transmission planning and operations. ***https://www.energy.siemens.com/cms/00000031/en/ueberuns/organizati/services/siemenspti/softwareso/Pages/psse_1439533.aspx***

3.2.1.d Avoided Energy Loss During Transmission & Distribution

In addition to avoiding electricity generation, power plant capacity additions, and T&D capacity additions, clean energy policies and programs can avoid energy losses during T&D when these resources are located near the electricity consumer. Avoided energy losses during T&D can be estimated by multiplying the estimated energy and capacity savings from clean energy

10 A projected embedded analysis approach based on historic data also exists, but is considered appropriate for cost allocation during ratemaking. For estimating avoided costs due to energy efficiency measures it is important to consider future capital investment plans, making the system planning approach preferable.

11 The investment in nominal costs is based on revenue requirements that include cost of capital, insurance, taxes, depreciation, and O&M expenses associated with T&D investment. (Feinstein et al., 1997; Orans et al., 2001; Lovins et al., 2002)

12 LOLP can be used to allocate the marginal capacity costs to time periods (NARUC, 1992, 118). A LOLP of 0.01 means there is a one percent probability that the utility might not be able to serve some or all of customer load. Because LOLP increases as customer usage increases, a LOLP-weighted marginal capacity cost will be high during high LOLP periods.

VERMONT USES SYSTEM PLANNING APPROACH TO ESTIMATE AVOIDED TRANSMISSION COSTS

The Vermont Electric Company (VELCO) owns and maintains the bulk transmission facilities in the state to serve all the electric distribution utilities. In 2003, VELCO undertook a study of alternatives to a proposed major upgrade in the northwest corner of Vermont. The transmission upgrade was reliability-driven and urgently needed, which resulted in a very high bar for alternatives. VELCO reached an agreement with the Vermont Department of Public Service to conduct a thorough study of distributed generation, energy efficiency, and new central generation as alternatives to the upgrade.

The study identified a range of central generation and distributed generation options and estimated their costs. In addition, a location-specific study of the available energy efficiency potential and the program costs for delivering that potential was prepared. Various combinations of energy efficiency and generation were assembled as alternatives to the proposed transmission project and compared based on total present value of cost of service. The study determined the cost of the transmission upgrade and the cost of a smaller upgrade so that the difference in those two costs could be used to assess the cost-effectiveness of the alternative resource package. While the alternatives were not adopted, due in part to the fact that only the transmission option's costs could be spread across the whole ISO region, this study demonstrates one way to use the system planning approach to estimate avoided transmission costs.

Source: LaCapra Associates, 2003; Orans, 1989; Orans, 1992.

policies and programs located near or at a customer site by the T&D energy loss percentage. An approach for determining the energy loss is described below.

The energy loss factor is the percent difference between the total energy supplied to the T&D system and the total energy taken off the system for delivery to end-use customers during a specified time period, calculated as 1 minus (delivered electricity/supplied electricity). T&D losses in the range of 6 percent to 10 percent are typical, which means that for every 1 kWh saved at the customer's meter, 1.06–1.10 kWh is avoided at the generator.

Line loss is typically higher when load is higher, especially at peak times when it can be as great as twice the average value. The line loss reductions from energy efficiency, load control, and DG are thus significantly higher when the benefits are delivered on peak than when they occur at average load levels, which greatly enhances the reliability benefits. A clean energy measure that saves 1.0 KWh of power at the customer's meter may save, for example, 1.2 KWh from the generator during peak hours simply because line losses are higher at peak times.

The significance of losses in high load periods is further increased by the high marginal energy costs and energy prices experienced at those times. Due to the variation in loads over the course of the year, T&D loss estimates are more precise when developed for short time periods (e.g., less than one year).

Utilities routinely collect average annual energy loss data by voltage level (as a percentage of total sales at that level). RTOs and ISOs also provide loss data. Note that transmission loss, which is smaller than distribution loss, may be included in wholesale energy prices in restructured markets.

Estimates of line loss can be applied to the energy impacts estimated as described in Chapter 2. If load profile information is available, then estimates can reflect the higher on-peak loss rate.

3.2.2 HOW TO ESTIMATE THE SECONDARY ELECTRIC SYSTEM BENEFITS OF CLEAN ENERGY RESOURCES

Clean energy policies and programs result in many additional electric system benefits that affect the efficiency of electric systems and energy markets. These *secondary* benefits have associated cost reductions, but the methodologies for assessing them are sometimes diverse, qualitative, and subject to rigorous debate. As described in Section 3.1, some of the key secondary benefits of clean energy to electric systems and markets include:

- Avoided ancillary service costs;
- Reductions in wholesale market prices;
- Increased reliability and improved power quality;
- Avoided risks associated with long lead-time investments, such as the risk of overbuilding the electric system;
- Reduced risks from deferring investments in traditional centralized resources until environmental and climate change policies take shape; and
- Improved fuel diversity and energy security.

The ability to estimate the secondary benefits of clean energy policies and programs and the availability of methods vary depending on the benefit. These

ANCILLARY SERVICES THAT CLEAN ENERGY RESOURCES CAN PROVIDE TO THE SYSTEM

Operating reserve – Spinning: Generation synchronized to the grid (i.e., "spinning") and usually available within 10 minutes to respond to a contingency event. For example, 50 MW of spinning operating reserve means that a generation unit can increase its output by 50 MW within 10 minutes.

Operating reserve – Supplemental: Generation that is available within 30 minutes but is not necessarily synchronized to the grid.

Reactive Power/Voltage Support: The ability of a generator to "absorb" or "generate" reactive power to meet voltage standards on the grid.

DEMAND RESPONSE COULD IMPROVE PLANT UTILIZATION AND REDUCE EMISSIONS IN NEW ENGLAND

Compared with other regional control areas, New England has a small amount of quick-start capacity relative to the regional peak load. As such, a number of large oil- and gas-fired steam units that do not have the ability to start quickly must run constantly to provide reserve capacity. A study conducted for the New England Demand Response Initiative (NEDRI) used a production costing model (PROSYM/MULTISYM) to evaluate how hypothetical aggressive demand response programs implemented during the summer of 2006 would affect power plant utilization and net emissions when such programs are used for reserve capacity. The study found that the demand response programs could result in more efficient plant utilization, reducing operation of the steam units, and increasing operation of efficient combined-cycle units in the region. If no diesel generators participate in the demand response programs, the study identified the additional potential for reductions in NOx, SO_2, and CO_2 emissions during the summer.

Source: Synapse Energy Economics, 2003.

methods are less mature than those for primary benefits, and as such tend to rely more upon non-modeling estimation approaches than more sophisticated simulation modeling ones. Secondary electric system benefits, and methods for estimating them, are described below.

3.2.2.a Avoided Ancillary Services Costs

"Ancillary services" is a catch-all term for electric generator functions needed to ensure reliability, as opposed to providing power, and include services such as operating reserves and voltage support.

Operating Reserves

Energy efficiency programs avoid the need for corresponding operating reserves (those generation resources available to meet loads quickly in the event a generator goes down or some other supply disruption occurs) and thus avoid the respective costs.

RTOs routinely report market prices for ancillary services. In those regions with ancillary service markets, such as PJM, NYISO, ISO-NE, ERCOT and the California RTO, services are provided at rates determined by the markets and thus are easily valued.[13] The market value of a given MW of clean energy short-term reserve is equal to the operating reserve price, as posted by the RTO or ISO on its Web site.

Voltage Support

Voltage support is important to ensure the reliable and safe operation of electricity-consuming equipment and the grid. There are few market metrics available to estimate the price of voltage support benefits. The reactive power provisions in Schedule 2 of the FERC pro forma open access transmission tariff, or an RTO's equivalent schedule for reactive support, can be used as a proxy for the avoided cost of voltage support. However, the Schedule 2 payments are often uniform across a large region. As a result, they may not capture differences in the value of these services in load pockets. Alternately, the difference in reliability with and without the clean energy resource can also give some indication of voltage support benefits. (See the reliability metrics discussion in Section 3.2.2.c *Increased Reliability and Power Quality*.)

Some clean energy measures can have direct beneficial effects on avoiding certain voltage support or reactive power requirements. Reactive power ancillary services are local in nature, and clean energy policies and programs that reduce load in a load pocket area can minimize the need for local reactive power requirements. On the other hand, solar and wind resources may require backup voltage support due to their intermittent nature.

It is important to note that the avoided costs of reactive power and other ancillary services are typically smaller than other costs, such as avoided energy, capacity, and T&D investment. For example, 2003 reactive power payments were only 0.52 percent of the total costs of serving load in PJM (Burkhart, 2005).

13 There can be opportunity costs associated with provision of operating reserve. Some regions allow demand response and other clean energy resources to bid directly into the energy market.

3.2.2.b Reduction in Wholesale Market Clearing Prices

In addition to the benefits of reduced wholesale electricity costs (i.e., avoided energy and capacity costs described in Section 3.3), clean energy resources can reduce the wholesale market clearing price for electricity as a result of decreased demand for electricity, gas, or both. This can directly benefit both utilities and consumers.

The methods for estimating short-run wholesale market price effects involve relatively well-understood data and are reasonably straightforward to apply. In contrast, wholesale market price effects over the long term involve relatively poorly understood relationships, and estimating these price effects can become quite complex. For this reason, this section presents the steps involved in estimating the magnitude of the price effects of resource additions in the near term using a basic approach. For longer-term forecasts, a more sophisticated approach such as a dispatch model may be preferred.

The potential market price decrease attributable to a particular clean energy resource can be estimated based on a load curve analysis as follows.

Step 1. Determine the time period for which the calculation is to be made.

Step 2. Determine the size of the clean energy resource (and the hourly shape if relevant), typically in MW. (For more information, see Step 1: Estimate Clean Energy Operating Characteristics in Section 3.2.1.a)

Step 3. Develop a dispatch curve that can be based upon either generating unit data (i.e., capacity ratings and operating costs) or market clearing price data (typically available from the ISO or control area operator). (For more information, see Step 2: Identify the Marginal Units to be Displaced in Section 3.2.1.a)

Step 4. Calibrate or validate the calculation for the case without the clean energy resource.

Step 5. Analyze a case with the clean energy resource by reducing demand or adding supply to represent the clean energy resource.

Step 6. Compare the wholesale market price results for the two cases. The difference is the wholesale market price reduction benefit (expressed in \$/MWh or total dollars for the time period).

This approach for calculating the market price change can be applied to the electric *energy* market and *capacity* market, if one exists in the region. This benefit can be calculated using spreadsheets, an electric system dispatch model (e.g., MAPS, ProSym), or an energy system model for a more aggregated estimate. Another approach, used by the CPUC in California's avoided cost proceeding, is to use historical loads and prices (CPUC, 2006).

PRICE EFFECTS OF DEMAND RESPONSE IN THE NORTHEAST IN JULY AND AUGUST, 2006

In all four of the structured, RTO-run eastern spot electricity markets, historically high peak load values occurred during a week-long heat wave in August 2006. Market coordinators from New York (over 1,000 MW of load reduction), PJM (520 MW of peak reduction) and New England (625 MW of peak reduction) all acknowledged the role that demand response played in keeping peak load lower than what otherwise would have occurred.

For example, PJM estimated that wholesale prices would have been \$300/MWh higher without demand response during the highest demand hours of the heat wave, corresponding to a reported savings of about \$650 million for energy purchasers. Payments to all demand response providers totaled only \$5 million; even considering the potential costs of demand response programs, such as program administration costs, the benefit-cost ratio is favorable.

Source: PJM, 2006a, PJM, 2006b.

PRICE EFFECTS DUE TO THE NEW YORK ENERGY \$MART PROGRAM

An evaluation of the cost-effectiveness of a portfolio of programs under NYSERDA's New York Energy \$mart public benefits program estimated the reduction in average wholesale electricity prices over the period 2006 (full implementation of program) to 2008 (the year after which no currently known planned new capacity is assumed to come online). The analysis used a production cost model, Multi Area Production Simulation Software (MAPS), to compare the average annual wholesale electricity commodity prices in two cases: one with the New York Energy \$mart[SM] Program (the base case), and a one without the program benefits (the sensitivity case). The study estimated electricity market price reductions of about \$11.7 million in 2003 to \$39.1 million (in 2004 dollars) in 2023 as a result of the program.

Source: Heschong Mahone Group, 2005.

3.2.2.c Increased Reliability and Power Quality

An expansion in the use of clean energy resources can improve both the reliability of the electricity system and power quality. For example, California's investments in energy efficiency, conservation, and demand response played a role in averting rolling blackouts in the summer of 2001. Power quality problems occur when there are deviations in voltage level supplied to electrical equipment. Some forms of clean energy resources, such as fuel cells, can provide near perfect power quality to their hosts.

Reliability Metrics

Although clean energy resources can improve system reliability, measuring these benefits can be difficult. The most common reliability metrics are indices, which are relatively well-established and straightforward to calculate (see text box, *Reliability Indices*). Historical reliability data are often available.

Converting reliability benefits into dollar values is complex, however, and the results of studies that have attempted to do so are controversial. For this reason, their use in support of resource decisions is less common than for other, well-established benefits, such as the avoided costs of generation, capacity, and T&D.

Power Quality Metrics

The data needed to assess power quality benefits are neither consistently measured nor comprehensively collected and reported. Specialized monitoring equipment is typically necessary to measure power defects, and acceptable standards for power quality have been changing rapidly.

Power quality improvements produce real economic benefits for electricity consumers by avoiding damage to equipment and associated loss of business income and product, and, in some cases, the need for redundant power supply. At the extreme, some commercial and industrial processes, such as silicon chip fabrication and online credit card processing, are so sensitive to outages or power quality deviations that customers take proactive steps to avoid these concerns, including construction of redundant transmission lines or installing diesel or battery backup power. The costs of such equipment could also be used to estimate the value of increased reliability and power quality.

RELIABILITY CONCEPTS

Reliability refers to the electric system's availability to consistently serve the demanded load.

Power Quality refers to the consistency of voltage of electricity supplied to electrical equipment (usually meaning the voltage stays within plus or minus 5 percent).

RELIABILITY INDICES

SAIFI (system average interruption frequency index): the average frequency of sustained interruptions per customer over a predefined area. It is calculated as the total number of customer interruptions divided by the total number of customers served.

SAIDI (system average interruption duration index): commonly referred to as customer minutes of interruption or customer hours, it provides information on the average time customers are interrupted. It is calculated as the sum of the restoration time for each interruption event times the number of interrupted customers for each interruption event divided by the total number of customers.

CAIDI (customer average interruption duration index): the average time needed to restore service to the average customer per sustained interruption. It is calculated as the sum of customer interruption durations divided by the total number of customer interruptions.

MAIFI (momentary average interruption frequency index): considers momentary interruptions resulting from each single operation of an interrupting device, such as a recloser. It is calculated as the total number of customer momentary interruptions divided by the total number of customers served.

RELIABILITY BENEFITS OF CLEAN ENERGY

Clean energy provides reliability benefits because when a small clean energy unit fails, the result is less catastrophic than when one large, traditional generating unit fails. For example, suppose a utility has the choice of installing one hundred kilowatts of clean DG around its system or installing a single 10 megawatt generator (100 units times 100 kW). In this situation, there would likely be a greater probability of the 10 MW generator being out of service than of finding all 100 of the smaller units out of service. Such an effect can either reduce the reserve margin required (which benefits both the utility and consumers) or, if the reserve margin is fixed, reduce the price of reserve capacity (Lovins et al., 2002).

THE IMPORTANCE OF POWER QUALITY

It is important to maintain consistent power quality; otherwise, electrical equipment can be damaged. For example, consumer and commercial electrical and electronic equipment is usually designed to tolerate extended operation at any line voltage within 5 percent nominal, but extended operation at voltages far outside that band can damage equipment or cause it to operate less efficiently.

3.2.2.d Avoided Risks Associated with Long Lead-time Investments Such as the Risk of Overbuilding the Electric System

Clean energy options provide increased flexibility to deal with uncertainty and risk related to large, traditional fossil fuel resources, including:

- Clean energy resources, such as wind and photovoltaics, reduce the impact on electric system costs from fuel price uncertainty relative to traditional resources, and lower the financial risks and costs associated with generation.
- In terms of resource planning, clean energy options offer great flexibility. If one is unsure that long-term forecasts for load growth are 100 percent accurate, then clean energy resources offer greater flexibility due to their modular nature and relatively quick installation times relative to traditional resources.[14]
- Clean energy resource options provide more time to develop technologically advanced, less polluting, more efficient, large-scale technologies.

All other things being equal, a resource or resource plan that offers more flexibility to respond to changing future conditions is more valuable than a less flexible resource or plan. Techniques such as decision tree analysis or real option analysis provide a framework for assessing this flexibility. These approaches involve distinguishing between events within one's control (i.e., decision nodes) and those outside of one's control (i.e., exogenous events) and developing a conceptual model for these events as they would occur over time. Specific probabilities are generally assigned to the exogenous events. The results of this type of analysis can include the identification of the best plan on an expected value basis (i.e., incorporating the uncertainties and risks) or the identification of lower risk plans.

Above and beyond the expected value of the plan, certain resources may have some "option value" if they allow (or don't foreclose) other resource options in the future. For example, a plan that involves implementing some DSM in the near term can have value above its simple short-run avoided cost, in that it develops the capability for expanded DSM deployment in the future if conditions call for it.

[14] *Of course, clean energy resources carry their own risk of non-performance.*

THE IMPORTANCE OF LOW PERFORMANCE CORRELATIONS

Similar resources (e.g., fossil fuels such as coal and oil) tend to face similar specific risks, and as a result their performances tend to be correlated. For example, coal and oil both emit CO_2 when burned and thus could be associated with future climate change regulatory risk, which in turn would likely increase costs and affect the performance of oil- or coal-fired generation. On the other hand, disparate resources (e.g., coal and wind) have lower performance correlations—and hence more value for offsetting resource-specific risks within the portfolio—than resources that have little disparity.

3.2.2.e Reduced Risks from Deferring Investment in Traditional, Centralized Resources Pending Uncertainty in Future Environmental Regulations

Clean energy resources offer planners options for mitigating current and future environmental regulation risks. Clean energy can reduce the cost of compliance with air pollution control requirements. Utilities and states also see clean energy as a way to reduce their financial risk from future carbon regulations.

For example, a 2008 study looked at 10 utilities in the western U.S. and examined how their respective resource plans accounted for future carbon regulations. The study found that the majority of the 10 utilities included aggressive levels of energy efficiency and renewable energy to reduce carbon emissions. The study also found that in making these decisions the utilities did not consider the indirect impacts of future carbon regulations, such as increased wholesale electric market price, retirements of conventional generation plants, and the impact on transmission and distribution expansion (Barbose et al., 2008).

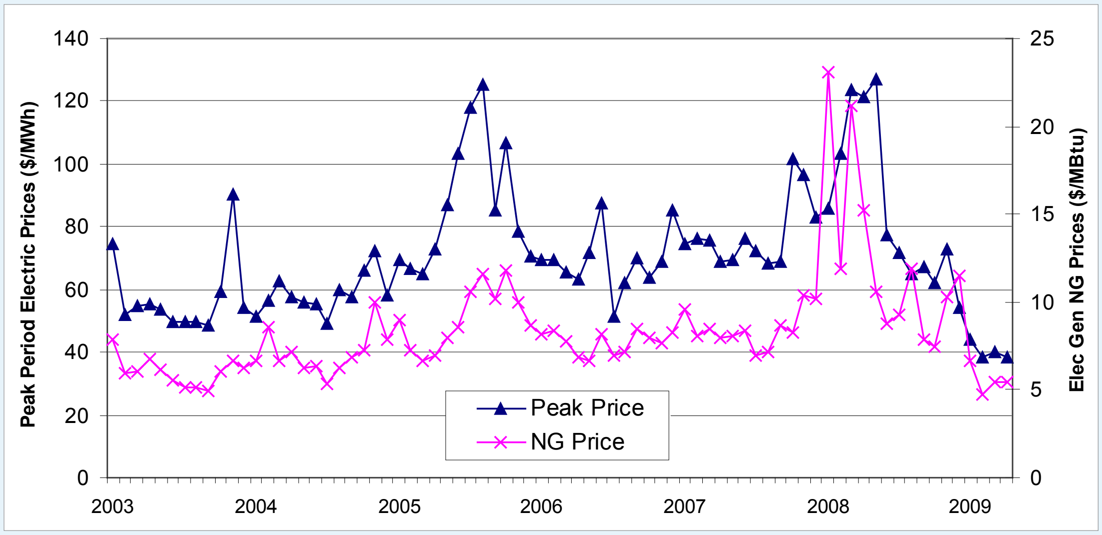
When comparing new generation options in the face of potential environmental regulations, some states and utilities are reducing financial risk by placing a higher cost premium on traditional resources relative to clean energy. For example, California has adopted an $8/ton carbon dioxide greenhouse gas adder to be used in comparing resources (Johnston et al., 2005; CA PUC, 2004).

3.2.2.f Improved Fuel Diversity and Energy Security

Portfolios that rely heavily on a few energy resources are highly affected by the unique risks associated with any single fuel source. In contrast, the costs of clean

FIGURE 3.2.5. NATURAL GAS AND ELECTRICITY PRICES IN NEW ENGLAND

A large portion of New England's electricity is generated from natural gas. Due to this high dependence on one fuel source, and because fuel represents a large portion of the cost to produce electricity, natural gas and electricity prices are highly correlated.



Sources: EIA; ISO NE, summary of monthly data, 2006.

energy resources are not affected by fossil fuel prices and thus can hedge against fossil-fuel price spikes by reducing exposure to this volatility.

Diversity in technology can also reduce the likelihood of supply interruptions and reliability problems. For example, while geothermal plants can be expensive to construct, they offer an almost constant supply of energy and are best suited for baseload generation. Gas turbines, on the other hand, are relatively inexpensive to construct and can start quickly, but have a high operating cost and so are best suited for peaking generation. Figure 3.2.5 illustrates the relationship between electricity and natural gas prices in New England.

Two approaches for estimating the benefits of fuel and technology diversification include market share indices and portfolio variance.

- *Market share indices.* Market share indices, such as the Herfindahl-Hirschmann Index and Shannon-Weiner index, identify the level of diversity as a function of the market share of each resource.[15] These indices are computationally simple and the data required for the indices (annual state electricity generation by fuel type and producer type) are readily available from the EIA Form 906 database.[16] Use of these indices is appropriate for preliminary resource diversity assessment and as a state or regional benchmark. Annual state electricity generation data by producer type and fuel type are available.

A limitation of these indices is that decisions on how to classify resources (e.g., calculating the share of all coal rather than bituminous and subbituminous coals separately) can have a large effect on the results. Another shortcoming is that the indices do not differentiate between resources that are correlated with each other (e.g., coal and natural gas) and thus can underestimate the portfolio risk when correlated resources are included.

- *Portfolio Variance.* The concept of portfolio theory suggests that portfolios should be assembled and evaluated based on the characteristics of the portfolio, rather than on a collection of individually assessed resources. Portfolio theory and portfolio variance measures account for risk and uncertainty by incorporating correlations between resources

15 *For more information about these indices, see U.S. Department of Justice and the Federal Trade Commission, Issued April 1992;* Shannon, C.E. "A mathematical theory of communication." ***Bell System Technical Journal*** 27: 379–423 and 623–656, July and October 1948.

16 *EIA Form 906 has been superseded by EIA Form 923. Both data sets are available at* ***http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html***

when projecting overall portfolio performance, as measured by the standard deviation of cost or some other measure of performance. The standard deviation can be calculated for a number of portfolios, each with a variety of different resources, to find portfolios that simultaneously minimize cost and risk. It is important to acknowledge this inherent trade-off between cost and risk; there is not a single portfolio that lowers both.

Like market share metrics, portfolio analysis does not readily incorporate the non-price and qualitative benefits of fuel diversity, such as energy independence, which can be a benefit of clean energy. It is safer to have many smaller, generating resource units that are located in a variety of locations and do not require fuel stored on-site than to have one easily targeted large unit. Also, using domestic clean energy resources to reduce dependence on foreign fuel sources, such as imported petroleum, may yield political and economic benefits by protecting consumers from supply shortages and price shocks. Care should be taken to consider price as well as factors that are not easily quantified when choosing among portfolios with different cost-risk profiles.

3.3 CASE STUDIES

The following two case studies illustrate how assessing the electric system benefits associated with clean energy can be used in the state energy planning and policy decision-making process.

3.3.1 CALIFORNIA UTILITIES' ENERGY EFFICIENCY PROGRAMS

Benefits Assessed

- Avoided electricity generation costs
- Avoided T&D costs
- Avoided environmental externality costs
- Avoided ancillary services costs
- Reduced wholesale market clearing prices

Clean Energy Program Description

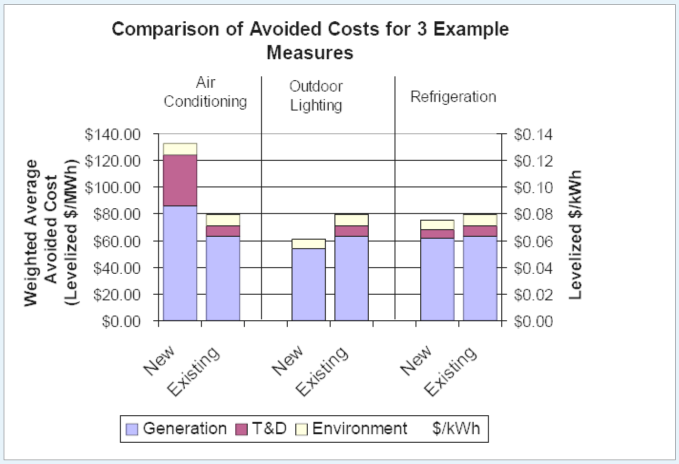
In 2005, the California Public Utilities Commission (CPUC) approved a new method for calculating avoided costs for use in evaluating 2006–2008 utility energy efficiency programs in California.

TABLE 3.3.1 COMPARISON OF OLD AND NEW AVOIDED COST METHODOLOGIES

	New Methodology		Old Methodology	
Avoided Cost	Time	Area	Time	Area
Avoided electricity generation costs	Hourly	Utility-specific	Annual Average Values	Statewide
Avoided Electric Transmission & Distribution Costs	Hourly	Utility, planning area and climate zone specific		
Avoided Natural Gas Procurement	Monthly	Utility-specific		
Avoided Natural Gas Transportation & Delivery	Monthly	Utility-specific		
Environmental externality Adders for Electric and Gas	Annual value, applied by hour per implied heat rate	System-wide (uniform across state)		
Reliability adder (Avoided ancillary services costs)	Annual value	System-wide (uniform across state)	None	None
Price elasticity of demand adder (Reduced wholesale market clearing prices)	Time of use period (on- vs. off-peak) by month	System-wide (uniform across state)	None	None

Source: E3 and RMI, 2004

FIGURE 3.3.1 COMPARISON OF AVOIDED COSTS FOR THREE EXAMPLE MEASURES



Source: E3 and RMI, 2004.

Method(s) Used

The methodology is described in a detailed report issued in October 2004, *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs* (E3 and RMI, 2004). The new methodology includes five major categories of costs that are avoided when demand is reduced through installation of energy efficiency resources. It produces time- and location-specific cost estimates, whereas the previous avoided cost methodology relied more upon average statewide values. Table 3.3.1 summarizes the differences between the old and new methodologies. The key findings of this study were based on the avoided costs derived from the new methodology and an avoided costs spreadsheet model that allows ongoing updates to account for changes in variables such as fuel prices.

Results

These results demonstrated the value of estimating avoided costs using time- and location-specific data by highlighting the importance of reducing demand during peak hours. It found that avoided costs (especially T&D avoided costs) were particularly high during peak hours and the peak summer season.

Figure 3.3.1 shows the results of avoided cost calculations for three different efficiency resources—air conditioning, outdoor lighting, and refrigeration programs—using both the new and existing methodologies. The largest difference in avoided costs between the new and the old methods occurred in the air conditioning program ($133/MWh with the new method compared with $80/MWh with the old method), illustrating the higher value placed on peak hour reductions. Outdoor lighting and refrigeration measures had lower avoided cost values when estimated with the new method than with the old method, because these appliances are used off-peak or throughout the day—many hours of which have very small avoided costs. Outdoor lighting appliances had the lowest values because they are used off-peak, when there are no avoided values for T&D. Since the initial avoided cost values were adopted, the CPUC adopted correction factors for residential and commercial air conditioning measures to better account for their previously undervalued peak load reduction contribution. [17] (CPUC, 2006)

As shown in Table 3.3.2, when applying this new methodology, California's energy efficiency programs are estimated to have a total program lifetime benefit of

[17] *Hourly avoided costs are averaged over the time-of-use periods for measures whose hourly load data are not available. Because this method did not use a load-weighted average, the measures that make a significant contribution to peak load reduction such as air conditioning were undervalued. To address this problem, the CPUC adopted correction factors for air conditioning measures to increase the averaged avoided cost values.*

TABLE 3.3.2 ESTIMATED COST EFFECTIVENESS TEST RESULTS FOR THE CALIFORNIA INVESTOR OWNED UTILITIES' 2006–2008 EFFICIENCY PROGRAMS

Costs & Benefits	SDG&E	SoCalGas	SCE	PG&E	Total
Total costs to billpayers (TRC)	$299,443,761	$225,381,390	$857,516,394	$1,341,473,455	$2,723,814,999
Total savings to billpayers (TRC)	$579.619,963	$318,003,849	$2,367,984,783	$2,153,115,608	$5,418,724,203
Net Benefits to billpayers	$280,176,202	$96,622,459	$1,510,468,390	$811,642,153	$2,694,909,204

Source: CPUC, 2005

$5.4 billion, twice as large as the cost of the programs[18] (CPUC, 2005).

For More Information

- *Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 - Phase 1 Issues.* California Public Utilities Commission. Interim Opinion. September 22, 2005. *http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm*

3.3.2 ENERGY EFFICIENCY AND DISTRIBUTED GENERATION IN MASSACHUSETTS

Benefit(s) Assessed

- Reduction in wholesale market clearing prices
- Avoided greenhouse gas (CO_2) emissions

Clean Energy Program Description

This study explores the potential price and emissions benefits of different options to increase distributed generation and energy efficiency in Massachusetts. The options include the addition of the following new demand resources over the baseline scenario through 2020:

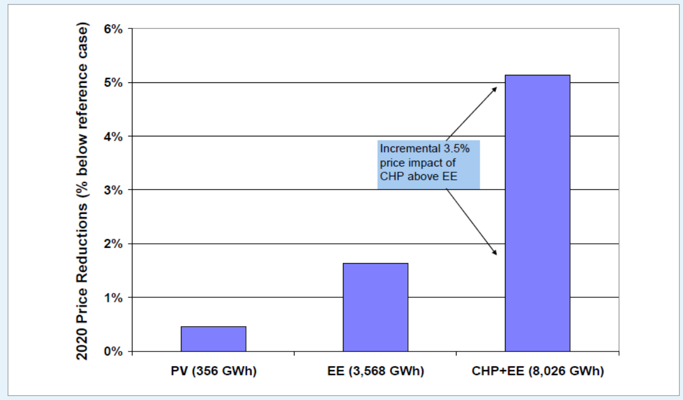
- photovoltaics (PV),
- energy efficiency (EE),
- combined heat and power (CHP), and
- combined EE and CHP.

Method(s)

The analysis required the development of a reference case to determine what the wholesale electric prices and carbon dioxide emissions would be without the additional clean energy resources. It assumed no ratepayer-funded investments in demand side management (DSM) programs beginning in 2007 and so it assumed energy savings achieved through the end of 2006 remain constant in the future. The reference case also assumed no new policies to encourage distributed generation.

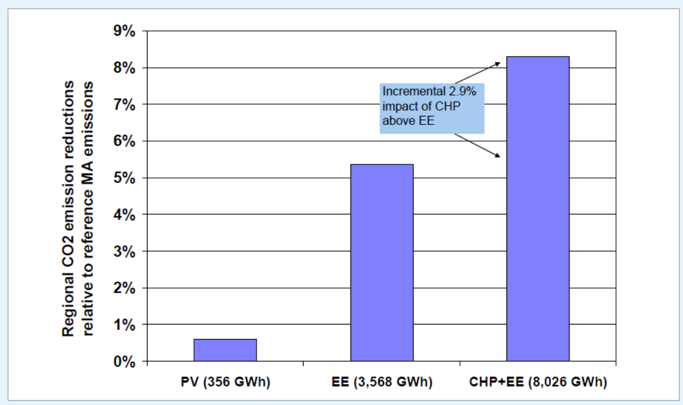
[18] *As a result of the energy efficiency programs, California's investor-owned utilities project savings of about 7,370 GWh of electricity, 1,500 MW of peak demand, and 122,000 megatherms of natural gas from 2006 to 2008. Relative to a base case without the programs, the utilities expect to reduce carbon dioxide emissions by about 6,600,000 tons — the equivalent of the emissions of about 1.2 million cars over the same period.*

FIGURE 3.3.2 REDUCTION IN AVERAGE ANNUAL WHOLESALE ELECTRIC ENERGY PRICE FOR MASSACHUSETTS PURCHASES IN 2020 UNDER PV, EE, AND CHP+EE CASES



Source: Impacts of Distributed Generation on Wholesale Electric Prices and Air Emissions in Massachusetts, Synapse Energy Economics, March 31, 2008.

FIGURE 3.3.3 REDUCTIONS IN REGIONAL CO2 EMISSIONS IN 2020 UNDER PV, EE, AND CHP+EE CASES RELATIVE TO REFERENCE CASE MASSACHUSETTS CO2 EMISSIONS



Source: Impacts of Distributed Generation on Wholesale Electric Prices and Air Emissions in Massachusetts, Synapse Energy Economics, March 31, 2008.

The analysis used the PROSYM simulation model to determine the potential price and emissions impacts of the scenarios. The model was used to simulate the average hourly wholesale market clearing prices and the regional greenhouse gas emissions (apportioned to Massachusetts based on GWh load) in 2020 under a reference case and each of the following four scenarios:

- 250 MW of incremental PV;
- Investment in EE sufficient enough to reduce annual growth of Massachusetts' energy consumption to 0.6 percent;
- 750 MW of incremental DG from CHP; and
- A combined CHP and EE case.

The scenarios are compared against the reference case to determine the impacts.

Results

The study projected that the combined effect of the PV, EE, and CHP would be to virtually eliminate load growth in Massachusetts.

In terms of impact on wholesale market prices:

- the 250MW of PV is expected to displace 356 GW of purchases from the wholesale market and reduce wholesale market prices by $.033/MWh or 0.4 percent,
- EE is expected to reduce prices by 1.6 percent, and
- the combined EE and CHP scenario would produce a 5.1 percent reduction in prices.

These market price changes will affect the wholesale energy costs paid by Massachusetts customers. Even though it is expected to achieve the lowest reduction in market clearing prices, PV is expected to achieve the largest wholesale market cost savings to Massachusetts consumers: $65 for every MWh generated by PV. EE is estimated to reduce costs by $24 for every MWh saved. The study estimates a savings of $35 per MWh of CHP generation. The values are different due to the different load shape profiles for each resource and the timing (and costs) for when each is likely to be used.

For greenhouse gas emissions, each of the alternative scenarios would achieve reductions of CO_2 emissions relative to the reference case. The combined EE and CHP scenario is likely to produce the greatest impact, with a reduction of 2.4 million short tons CO_2 /year in 2020. The majority of these reductions come from EE.

For More Information

- *Impacts of Distributed Generation on Wholesale Electric Prices and Air Emissions in Massachusetts*, Synapse Energy Economics, March 31, 2008. *http://www.masstech.org/dg/2008-03-Synapse-DG-Impacts-on-NE.pdf*

Information Resources	
Resource	**URL Address**
Summary of Rigorous Modeling Tools	
EnerPrise Market Analytics (powered by PROSYM)	*http://www1.ventyx.com/analytics/market-analytics.asp*
Multi-Area Production Simulation (MAPS)	*http://www.gepower.com/prod_serv/products/utility_software/en/ge_maps/index.htm*
Plexos for Power Systems	*http://www.energyexemplar.com*
PowerBase Suite (including Promod IV)	*http://www1.ventyx.com/analytics/promod.asp*
Capacity Expansion available from Ventyx	*http://www1.ventyx.com/products-services.asp*
PowerBase Suite (including Strategist)	*http://www1.ventyx.com/products-services.asp*
IPM available from ICF International	*http://www.icfi.com/Markets/Energy/energy-modeling.asp#2*
PROSYM	*http://www1.ventyx.com/analytics/market-analytics.asp*

Information Resources	
Resource	**URL Address**
Primary Electric System Benefits	
Bureau of Economic Analysis	*http://www.bea.gov*
California Database for Energy Efficient Resources (DEER). California Energy Commission database.	*http://www.energy.ca.gov/deer*
California ISO	*http://oasis.caiso.com/*
California Public Utilities Commission (CPUC) 2006. Interim Opinion: 2006 Update of Avoided Costs and Related Issues Pertaining to Energy Efficiency Resources. Decision 06-06-063 June 29, 2006	*http://www.cpuc.ca.gov/PUBLISHED/COMMENT_DECISION/56572.htm#P86_2251*
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FERC Form 1	*http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp*
FERC Form 714 (control area info)	*http://www.ferc.gov/docs-filing/eforms/form-714/overview.asp*
FERC Form 423 (cost and quality of fuels)	*http://www.eia.doe.gov/cneaf/electricity/page/eia423.html*
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NYISO	*http://www.nyiso.com/public/index.jsp*
NYMEX	*http://www.nymex.com/index.aspx*
Platt's MegaWatt Daily publishes forward electricity market prices through this paid subscription newsletter.	*http://www1.platts.com/Electric%20Power/Newsletters%20&%20Reports/Megawatt%20Daily/*

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PJM	*http://www.pjm.com/index.jsp*
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SEC 10K filings.	*http://www.sec.gov/edgar/searchedgar/companysearch.html*
State regulatory commission rate base and fuel clause adjustment filings	*http://www.naruc.org/*
The Massachusetts DG Collaborative Benefits and Costs of Distributed Generation website compiles a comprehensive list of studies regarding costs and benefits of distributed generation and distribution planning including the analysis conducted by the Massachusetts DG Collaborative and Navigant Consulting Inc.	*http://www.masstech.org/dg/Benefits.htm*
This Excel lookup table contains distribution system deferral values for each of the utilities included in the Distribution System Cost Methodologies paper by Shirley W. (2001) for the Regulatory Policy Project's Distributed Resource Policy Series.	*http://www.raponline.org/Pubs/DRSeries/CostTabl.zip*
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