National Standard Practice Manual

For Benefit-Cost Analysis of Distributed Energy Resources

Summary

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Acknowledgements

This *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM or the manual) is a publication of the National Energy Screening Project (NESP). The NESP is represented by a stakeholder group of organizations and individuals working to update and improve cost-effectiveness screening practices for distributed energy resources.

This manual incorporates and expands upon the guidance from the 2017 *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, which presented the NSPM Framework, fundamental benefit-cost analysis principles, and guidance specific to energy efficiency resources.

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This manual and related materials, including prior NSPM publications, are available at: www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

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NSPM SUMMARY

The purpose of this *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM, or the manual) is to help guide the development of jurisdictions' cost-effectiveness test(s) for conducting benefit-cost analyses (BCAs) of distributed energy resources (DERs). BCAs involve a systematic approach for assessing the cost-effectiveness of investments by consistently and comprehensively comparing the benefits and costs of individual or multiple types of DERs with each other and with alternative energy resources.

This manual includes information for conducting BCAs of single and multiple types of DERs and provides use case examples that illustrate BCAs under different combinations and applications of DERs. The DER types covered in this manual are: energy efficiency (EE); demand response (DR); distributed generation (DG); distributed storage (DS); electric vehicles (EV); and increased electrification of buildings including heating and cooling systems.

Distributed Energy Resources (DERs) are resources located on the distribution system that are generally sited close to or at customers' facilities. DERs include EE, DR, DG, DS, EVs, and increased electrification of buildings. DERs can either be on the host customer side of the utility interconnection point (i.e., behind the meter) or on the utility side (i.e., in front of the meter). DERs are mostly associated with the electricity system and can provide all or some of host customers' immediate power needs and/or support the utility system by reducing demand and/or providing supply to meet energy, capacity, or ancillary services (time and locational) needs of the electric grid.

DERs represent a critical component of the evolution of the electricity grid by allowing for a more flexible grid, enabling two-way flows of energy, enabling third parties to introduce and sell new electricity products and services, and empowering customers to optimize their end-uses and consumption patterns to lower their bills and utility costs.

This manual is built around a BCA framework (the NSPM BCA Framework) that defines the steps a jurisdiction can use to develop its primary cost-effectiveness test—the Jurisdiction-Specific Test (JST). The framework also provides guidance on how consider and develop secondary tests, where applicable. The NSPM BCA Framework includes a set of core principles that are the foundation for developing and applying cost-effectiveness tests for BCAs.

The NSPM is policy-neutral in that it does not recommend any specific cost-effectiveness tests or policies, but rather supports BCA practices that align with a jurisdiction's policy goals and objectives. The manual thus serves as an objective, technology-neutral and economically sound guidance document for regulators, utilities, consumer advocates, DER proponents, state energy offices, and other stakeholders interested in comprehensively assessing the impacts of DER investments.

This manual incorporates and expands upon the guidance from the 2017 *NSPM for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM for EE). Both documents are products of the National Energy Screening Project (NESP), a multi-year effort guided by an advisory group represented by a range of experts with varying perspectives involved in BCA of DERs.

This NSPM provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources.

Terminology and Applicability of the NSPM

This manual uses many terms that are commonly used within the electricity and gas industries. Key terms are defined in a Glossary and in relevant sections of the manual. Some of the terms used in the manual are more broadly defined than in other applications, as noted below.

NSPM Terminology

Jurisdiction refers broadly to any region or service territory that would be served by the DERs being analyzed. This includes a state, a province, a utility service territory, a city or a town, or some other jurisdiction covered by regulators or other entities that oversee DER initiatives.

Utility refers broadly to any entity that funds, implements, or supports DERs using customer or public funds that are overseen by regulators or other decision-makers. This includes investor-owned utilities; publicly owned utilities (e.g., municipal or cooperative utilities); program administrators; community choice aggregators; regional transmission organizations and independent system operators; federal, state, and local governments; and others. *Utility expenditures* refers to spending by any of these entities on DERs.

Regulator refers broadly to any entity that oversees and guides DER analyses. This includes legislators and their staff; public utility commissions and their staff; boards overseeing public power authorities, municipal or cooperative utilities, or regional grid operators; and federal, state, and local governments.

Host customer refers to any customer that has a DER installed and/or operated on their site. In some cases, these are program participants (such as in a DR or EE program) while in other cases there is no program (such as with EV owners).

Third parties refer to the broad range of independent providers such as aggregators or implementation, service, or technology providers.

The principles and concepts presented in this manual are relevant to:

1. DER programs, procurements, or pricing mechanisms associated with expenditures on behalf of the public or utility customers, whether by utilities or others. For simplicity, these are referred to these as ‘utility expenditures.’
2. Any jurisdiction where DERs are funded, acquired, or otherwise supported by electric or gas utilities or others on behalf of their customers.
3. All types of electric and gas utilities, including investor-owned and publicly owned utilities (e.g., municipal or cooperative utilities.)
4. All types of utilities, including utilities that are vertically integrated, transmission and distribution (T&D), or distribution-only utilities, or those serving as a distribution platform for host customers to access a variety of energy services and DERs from third parties (e.g., aggregators).
5. Single DER and multiple DER BCA analyses, where:
    - *Single-DER analyses* involve assessing *one DER type* in isolation from other DER types, relative to a static set of alternative resources.
    - *Multiple-DER analyses* involve assessing more than one DER type at the same time relative to a *static or dynamic* set of alternative resources. Multiple-DER analyses covered in this manual include multiple *on-site* DERs, non-wires solutions within a specific *geographic area*, and *system-wide* DER portfolios.

- *Dynamic system planning* involves assessing multiple DER types relative to a dynamic set of alternative resources. Under this approach, the goal is to optimize both DERs and alternative utility-scale resources as well. This practice is relatively nascent and still evolving.

While the NSPM addresses BCA for single and multi-DER scenarios, it does not address every nuance or application for DER investments.

Manual Contents

The NSPM includes five parts:

- Part I presents the NSPM BCA Framework, including fundamental principles and guidance on the development of primary and any secondary cost-effectiveness tests.
- Part II describes the full range of potentially relevant DER benefits and costs (i.e., impacts), and presents several cross-cutting considerations on how to account for certain impacts.
- Part III provides guidance on single-DER BCA for various types of DER technologies. These chapters provide guidance on key factors and challenges that affect the impacts of each DER type.
- Part IV provides guidance on multiple-DER analysis. It addresses the three main ways that multiple-DER analysis is conducted: for a customer site; for a geographic region; and for an entire utility service territory. Part IV also addresses, at a high level, dynamic system planning.
- Appendices provide further detail on topics that warrant additional explanation. The appendices also provide information and templates on reporting BCA results.

Part I: The NSPM BCA Framework

Part I presents the NSPM BCA Framework, comprising three elements:

1. A set of **fundamental principles** that serve as the foundation for assessing the cost-effectiveness of potential DER investments in an economically sound and policy-neutral manner;
2. A **multi-step process** for developing or informing a jurisdiction's primary test—the Jurisdiction-Specific Test (JST)—as guided by the NSPM principles; and
3. Guidance on **when and how to use secondary tests** to inform (a) the prioritization of cost-effective DERs, as determined by a primary JST, and (b) decisions around marginally non-cost-effective DERs.

The **NSPM principles** in and of themselves do not determine a jurisdiction's appropriate cost-effectiveness test for DERs. The NSPM principles are intended to be applied in a manner that takes into consideration the characteristics and circumstances of each jurisdiction's approach to energy resources and can result in different JSTs for different jurisdictions.

Fundamental BCA Principles

The NSPM provides a set of fundamental BCA principles that represent sound economic and regulatory practices. The NSPM BCA principles presented in Table S-1 set the foundation for developing cost-effectiveness tests for BCA. The principles can be used to guide the application of cost-effectiveness testing, selection of a discount rate, and the reporting of the BCA results, and they can inform the process for prioritizing DERs to be implemented.

The NSPM BCA principles are not mutually exclusive as they contain some overlapping concepts. Further, there may be situations where it is necessary for jurisdictions to make tradeoffs between certain principles depending on specific situations.

Table S-1. NSPM BCA Principles

Principle 1	**Treat DERs as a Utility System Resource** DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
Principle 2	**Align with Policy Goals** Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.
Principle 3	**Ensure Symmetry** Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
Principle 4	**Account for Relevant, Material Impacts** Cost-effectiveness tests should include all relevant (according to applicable policy goals), material impacts including those that are difficult to quantify or monetize.
Principle 5	**Conduct Forward-Looking, Long-term, Incremental Analyses** Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
Principle 6	**Avoid Double-Counting Impacts** Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
Principle 7	**Ensure Transparency** Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
Principle 8	**Conduct BCAs Separately from Rate Impact Analyses** Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.

Process for Developing a Primary Jurisdiction-Specific Test

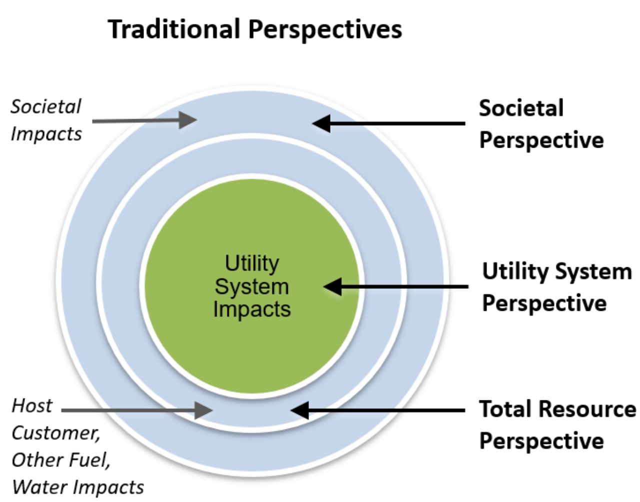
The primary test answers the critical question: Which DERs have benefits that exceed costs and therefore merit utility acquisition or support on behalf of customers?

The NSPM presents a step-by-step process for developing a primary cost-effectiveness test (or modifying an existing primary test). Referred to as the ‘JST’, this test reflects the fundamental BCA principles in Table S-1.

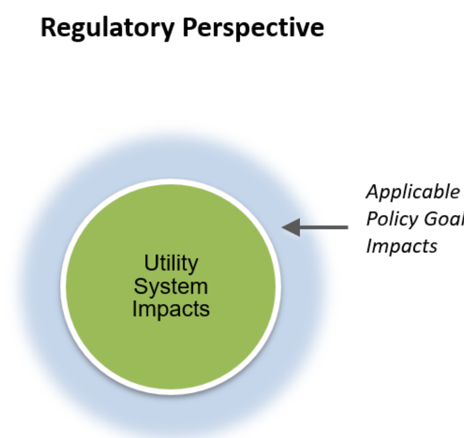
This manual presents the regulatory perspective, which refers to the perspective of regulators or similar entities that oversee utility DER investment decisions. A JST should reflect the regulatory perspective to ensure proper accounting of the jurisdiction’s applicable policy goals—as guided by statutes, regulations, organizational policies, utility resource planning principles and policies, and/or other codified forms under which utilities or energy providers operate.

Figure S-1 illustrates the regulatory perspective relative to traditional cost-effectiveness test perspectives.

Figure S-1. The Regulatory Perspective



- Three perspectives define the scope of impacts to include in the most common traditional cost-effectiveness tests.



- Perspective of public utility commissions, legislators, muni/coop boards, public power authorities, and other relevant decision-makers.
- Accounts for utility system plus impacts relevant to a jurisdiction’s applicable policy goals (which may or may not include host customer impacts).
- Can align with one of the traditional test perspectives, but not necessarily.

Table S-2 presents the multi-step process for developing a JST. This process provides the flexibility for each jurisdiction to tailor its primary JST to its own goals and objectives.

Table S-2. Developing a Jurisdiction's Primary Test: A 5-Step Process

STEP 1 Articulate Applicable Policy Goals

Articulate the jurisdiction's applicable policy goals related to DERs.

STEP 2 Include All Utility System Impacts

Identify and include the full range of utility system impacts in the primary test, and all BCA tests.

STEP 3 Decide Which Non-Utility System Impacts to Include

Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:

- Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.

STEP 4 Ensure that Benefits and Costs are Properly Addressed

Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:

- Benefits and costs are treated symmetrically.
- Relevant and material impacts are included, even if hard to quantify.
- Benefits and costs are not double-counted.
- Benefits and costs are treated consistently across DER types.

STEP 5 Establish Comprehensive, Transparent Documentation

Establish comprehensive, transparent documentation and reporting, whereby:

- The process used to determine the primary test is fully documented.
- Reporting requirements and/or use of templates for presenting assumptions and results are developed.

When deciding whether to include a benefit or cost in a BCA test, it is important to distinguish between the *definition* versus *application* of the BCA test. Any impact that is deemed to be relevant should be included as part of the definition of the test. In some cases, a benefit or cost may be relevant but not material. *Material* impacts are those that are expected to be of sufficient magnitude to affect the result of a BCA. Impact determined to be immaterial should be documented, but not necessarily included in the application of the BCA test.

Secondary BCA Tests

The NSPM also provides guidance on how secondary tests can be used to help assess marginally cost-effective DERs or to prioritize across DERs. While a jurisdiction's primary test should be used to inform whether a utility should fund or otherwise support DERs, it does not have to be utilized in a vacuum. In some instances, secondary tests can help enhance regulators' and stakeholders' overall understanding of DER impacts by answering other questions regarding utility DER investments. Different tests provide different information about the cost-effectiveness and impacts of DERs. However, secondary tests should be used cautiously to ensure that they do not make the BCA decision-making process burdensome or undermine the purpose of the primary test.

This manual does not prescribe any one cost-effectiveness test. Because the JST is based upon each jurisdiction's applicable policy goals, and those goals can vary across jurisdictions, the test may take a variety of forms. Further, depending on a jurisdiction's applicable policy goals, the primary test may or may not align with traditional BCA tests (e.g., the Total Resource Cost test.)

Part II. DER Benefits and Costs and Cross-Cutting Considerations

Part II of the manual presents a catalog of the full range of benefits and costs that may be applicable to specific types of DERs. This catalog can be used as a reference when deciding which types of benefits and costs should be included in a jurisdiction's BCA test.

The catalog of impacts is presented in table format and supported with detailed descriptions of each impact type. Table S-3 shows the range of potential DER impacts to the electric utility system, along with descriptions of each impact. Similarly, Table S-4 and Table S-5 provide a summary of potential host customer and societal impacts, respectively. Part II also addresses natural gas and other fuel system impacts and specific host customer non-energy impacts (NEIs).

Table S-3. Potential DER Impacts: Electric Utility System

Type	Utility System Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Environmental Compliance	Actions to comply with environmental regulations
	RPS/CES Compliance	Actions to comply with renewable portfolio standards or clean energy standards
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption
	Ancillary Services	Services required to maintain electric grid stability and power quality
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably
	Transmission System Losses	Electricity or gas lost through the transmission system
Distribution	Distribution Capacity	Maintaining the availability of the distribution system to transport electricity or gas safely and reliably
	Distribution System Losses	Electricity lost through the distribution system
	Distribution O&M	Operating and maintaining the distribution system
	Distribution Voltage	Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand
General	Financial Incentives	Utility financial support provided to DER host customers or other market actors to encourage DER implementation
	Program Administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of DER programs
	Credit and Collection	Bad debt, disconnections, reconnections
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions

Table S-4. Potential Benefits and Costs of DERs: Host Customer

Type	Host Customer Impact	Description
Host Customer	Host portion of DER costs	Costs incurred to install and operate DERs
	Host transaction costs	Other costs incurred to install and operate DERs
	Interconnection fees	Costs paid by host customer to interconnect DERs to the electricity grid
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER
	Reliability	The ability to prevent or reduce the duration of host customer outages
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts
	Low-income NEIs	Non-energy benefits and costs that affect low-income DER host customers

Table S-5. Potential Costs and Benefits of DERs: Societal

Type	Societal Impact	Description
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers
	GHG Emissions	GHG emissions created by fossil-fueled energy resources
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts
	Economic and Jobs	Incremental economic development and job impacts
	Public Health	Health impacts, medical costs, and productivity affected by health
	Low-Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures
	Energy Security	Energy imports and energy independence

In addition to describing the range of potential DER impacts, Part II also addresses key cross-cutting benefit and cost issues, including the following:

- *Temporal and Locational Impacts of DERs*: Several of the benefits and costs of some DERs can vary significantly depending on when the DER operates and where it is located. DER benefits and costs should be estimated using temporal and locational detail sufficient to adequately represent the DER operating patterns and consequent benefits and costs.
- *Interactive effects between individual DERs*: Some DERs can have interactive effects on other DERs in terms of affecting avoided costs, affecting the magnitude of kWh and kW impacts, and enabling the adoption of other DERs. These interactive effects should be accounted for in BCAs for those instances where they are likely to have a material effect.

- *Air emission impacts*: Greenhouse gas (GHG) and other air emission impacts will depend upon when the DER operates and which energy resources are displaced at that time. Estimates of GHG and other air emission impacts should account for the temporal and marginal DER impacts in as much detail as necessary to reflect these effects.
- *Renewable generation impacts*: DERs can support renewable electricity generation by providing grid flexibility and ancillary services. DERs can also reduce (or increase) the need to curtail renewable resources during times when renewable generation exceeds customer load. These impacts on renewable generation should be accounted for when they are expected to have a material effect on the BCA results.
- *Discount rates*: The choice of discount rate to use for a BCA can often have a very large effect on the result of the analysis. This choice should be guided by the jurisdiction's applicable policy goals and the regulatory perspective.

DER impacts identified for inclusion in a jurisdiction's BCA should ideally be estimated in monetary terms. Monetary values provide a uniform way to compile, present, and compare benefits and costs. While some DER impacts are difficult to quantify in monetary terms—either due to the nature of the impact or the lack of available information about the impacts—approximating hard-to-quantify impacts using best available information is preferable to arbitrarily assuming a value, including assuming that the relevant impacts do not exist or have no value. Further, some approximation may be necessary to ensure symmetry in the treatment of benefits and costs for certain relevant impacts.

Part III: BCA for Specific DER Types

Part III of the NSPM contains five chapters that discuss individual characteristics and impacts of each DER type covered in this manual: EE, DR, DG, DS, and electrification (including managed charging and discharging of EVs). Part III describes and provides guidance on key factors and challenges that affect the impacts of each DER type.

Table S-6, Table S-7, and Table S-8 show the range of benefits and costs in terms of their applicability to each DER. They indicate which impacts are typically a benefit, a cost, or either depending on the specific DER use case. The tables are a compilation of the DER-specific tables presented in Chapters 6–10 of the manual.

Table S-6. Potential Benefits and Costs: Electric Utility System

Type	Utility System Impact	EE	DR	DG	Storage	Electrification
Generation	Energy Generation	🟢	🟠	🟢	🔴	🔴
	Capacity	🟢	🟢	🟢	🟠	🔴
	Environmental Compliance	🟢	🟠	🟢	🟠	🔴
	RPS/CES Compliance	🟢	🟠	🟢	🔴	🔴
	Market Price Effects	🟢	🟢	🟢	🟠	🔴
	Ancillary Services	🟢	🟢	🟠	🟠	🔴
Transmission	Transmission Capacity	🟢	🟢	🟠	🟠	🟠
	Transmission System Losses	🟢	🟢	🟢	🟠	🔴
Distribution	Distribution Capacity	🟢	🟢	🟠	🟠	🔴
	Distribution System Losses	🟢	🟢	🟢	🟠	🔴
	Distribution O&M	🟢	🟢	🟠	🟠	🔴
	Distribution Voltage	🟢	🟢	🟠	🟠	🔴
General	Financial Incentives	🔴	🔴	🔴	🔴	🔴
	Program Administration Costs	🔴	🔴	🔴	🔴	🔴
	Utility Performance Incentives	🔴	🔴	🔴	🔴	🔴
	Credit and Collection Costs	🟢	🟢	🟢	🟢	🟢
	Risk	🟢	🟢	🟠	🟢	🔴
	Reliability	🟢	🟢	🟠	🟢	🔴
	Resilience	🟢	🟢	🟢	🟢	○

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-7. Potential Benefits and Costs of DERs: DER Host Customer

Type	Host Customer Impact	EE	DR	DG	Storage	Electrification
Host Customer	Host portion of DER costs	🔴	🔴	🔴	🔴	🔴
	Interconnection fees	○	○	🔴	🔴	○
	Risk	🟢	○	🟠	🟢	🟠
	Reliability	🟢	🟠	🟢	🟢	🟠
	Resilience	🟢	🟠	🟢	🟢	🟢
	Tax Incentives	🟢	🟢	🟢	🟢	🟢
	Host Customer NEIs	🟠	🟠	🟠	🟠	🟠
	Low-income NEIs	🟢	🟢	🟢	🟢	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Table S-8. Potential Benefits and Costs of DERs: Societal

Type	Societal Impact	EE	DR	DG	Storage	Electrification
	Resilience	🟢	🟢	🟢	🟢	🟠
	GHG Emissions	🟢	🟠	🟢	🟠	🟠
	Other Environmental	🟢	🟠	🟢	🟠	🟠
	Economic and Jobs	🟢	🟢	🟢	🟠	🟠
	Public Health	🟢	🟠	🟢	🟠	🟠
	Low Income: Society	🟢	🟢	🟢	🟢	🟢
	Energy Security	🟢	🟢	🟢	🟠	🟢

🟢 = typically a benefit for this resource type; 🔴 = typically a cost for this resource type; 🟠 = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type

Part IV: BCA for Multiple DER Types

The manual addresses BCA for different applications where multiple DER types might be combined, including:

- multiple on-site DER types, such as grid-integrated efficient buildings (GEB);
- multiple DER types in a specific geographic location in the form of a non-wires solution (NWS);
- multiple DER types across a utility service territory; and
- dynamic system planning practices that can be used to optimize DERs and alternative resources.

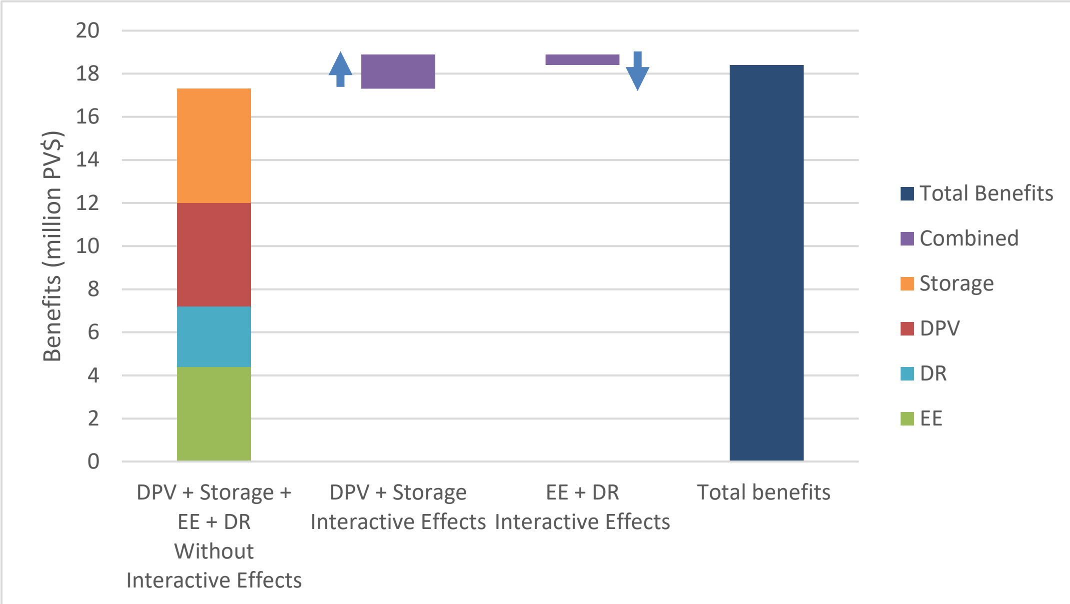
Multiple On-site DERs

Multiple on-site DERs can be installed in a variety of ways:

- On a residential level, utilities programs provide incentives to adopt multiple DER types that can then be used to benefit the customer and the grid.
- On a residential and commercial level, the aggregation of DERs in grid-interactive efficient buildings (GEBs) can provide grid support at scale.
- On a community level, DERs in microgrids and smart neighborhoods can be aggregated to provide grid support at scale.

The potential benefits and costs of multiple on-site DERs will depend on the type of DERs deployed, their capabilities, locational and temporal impacts, seasonal and daily load profiles, resource ownership and control of the DERs (i.e., level of dispatchability), and interactive effects across the DERs. Figure S-2 shows how the interactive effects between distributed photovoltaics and storage and between EE and DR can affect the total benefits of a GEB.

Figure S-2. Interactive Effects in Grid-Interactive Efficient Building



Non-Wires Solutions

These solutions focus on instances where utilities or others seek to install multiple DER types in a specific geographic area for the purpose of deferring or avoiding new investments in distribution or transmission systems. In these cases, cost-effectiveness will be very project-specific, depending on the specific transmission or distribution upgrade being deferred, the length of deferral, the mix of DERs producing the deferral, and a range of other factors. Due to the nature of T&D deferrals and uncertainty of load forecasts, NWS BCAs account for a project's number of years of deferral, which can shift depending on changing load forecasts.

Other key considerations for BCAs of NWSs include:

- When NWS projects are based on existing or new customer-sited DER programs, it is critical to accurately forecast customer participation and adoption, to reduce risk of not meeting requirements.
- Interactive effects should be accounted for, including effects on avoided costs, effects on kWh or kW impacts, and enabling effects.
- DERs geographically deployed to defer a T&D upgrade can have broader impacts on the utility system (e.g., avoided energy and generation capacity costs) as well as broader impacts related to policy objectives (e.g., avoided emissions).

<u>Illustrative Example of BCA for an NWS Project</u>

This manual provides an illustrative example of how a jurisdiction's primary test developed using NSPM can be applied to a hypothetical NWS project. The example assumes that a hypothetical state has developed its primary cost-effectiveness test (or modified its existing primary test) using the 5-step process described in Table S-2.

The state's JST accounts for conventional overarching goals of providing safe, reliable, resilient, and reasonably priced electricity services, as well as the goal of reducing GHG emissions (as articulated in statute). The JST also accounts for host customer impacts.

Non-Wires Solution Case Study Assumptions

In this example, an electric utility is facing the need to upgrade its system infrastructure due to distribution capacity constraints identified in a densely populated geographic area within its service territory. The utility proposes to integrate DERs to serve as a non-wires solution in place of an infrastructure upgrade.

The NWS plan includes the following BTM DERs in residential and commercial buildings:

- Energy efficiency measures (e.g., lighting and controls)
- Demand response (e.g., Wi-Fi-enabled thermostats)
- Distributed photovoltaics
- Distributed storage systems

Jurisdiction-Specific Test: The hypothetical jurisdiction's primary BCA test accounts for utility system, host customer, and GHG emission impacts.

Key assumptions:

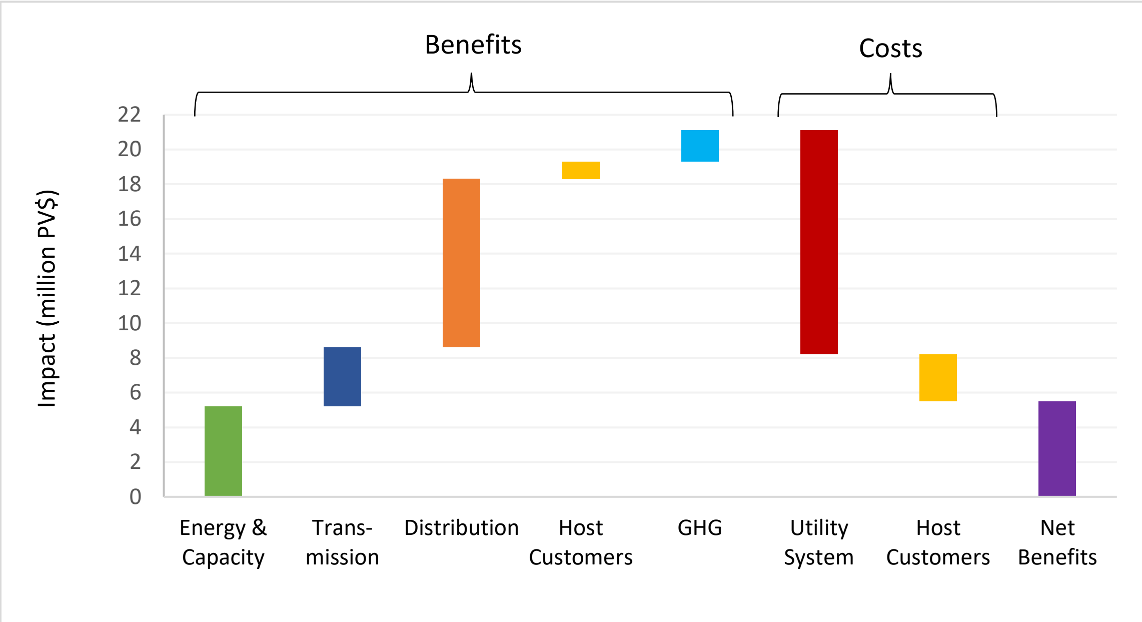
- *Non-Coincident Peak:* The distribution need is non-coincident with the overall system peak (e.g., the constrained distribution feeder peaks from 1:00–5:00pm, while system peaks from 5:00–9:00pm).
- *GHG Emissions Reduction:* The system-peak hours entail higher marginal emissions rates than the NWS, which allows the NWS to deliver GHG benefits.
- *DER Operating Profiles:* The NWS DERs operate in the following ways:
    - All DERs are operated to reduce the distribution peak, and some can reduce the system peak as well.
    - Storage charges during the distribution off-peak hours and discharges during the distribution peak hours.
    - DR reduces demand during distribution peak periods and/or shifts load from distribution peak periods to distribution off-peak periods.
    - Distributed PV resources generate during a portion of distribution peak period.
    - EE helps to reduce demand during distribution peak periods.

The example NWS benefits and costs associated with utility system, host customer, and GHG impacts are summarized below and presented in Figure S-3.

- *Generation Benefits* – Some generation benefits (e.g., energy generation, capacity, and ancillary services) accrue from targeting operation of DERs, such as storage and DR, during distribution peak periods. There will be additional benefits that result from some DERs—such as DPV and EE—also operating during other off-peak periods.
- *Transmission Benefits* – Some transmission benefits (e.g., capacity and system losses) accrue with the reduced delivery of central generation to customers.
- *Distribution Benefits* – The greatest contributor to the overall cost-effectiveness analysis is the direct benefit of operating DERs as much as possible during distribution peak periods.
- *GHG Benefits* – In this example, the GHG emissions are higher during the distribution system peak periods than the other periods. Consequently, the peak demand reductions from the NWS will result in a net reduction in GHG emissions.
- *General Utility Costs* – Financial incentives for customers to participate and administrative costs lead to the more substantive general utility costs for this illustrative analysis.
- *Host Customer Impacts* – Host customer costs include interconnection fees, transaction costs, and DER costs, while benefits include various non-energy impacts.

Figure S-3 combines the net benefits and costs of utility system, host customer, and GHG impacts. In this case study, locational value plays a central role in the cost-effectiveness of an NWS, as represented by the significant distribution benefits. The BCA indicates that the NWS will have net benefits.

Figure S-3. Illustrative Example of NWS Cost-Effectiveness



System-Wide DER Portfolios

The NSPM provides guidance on how to analyze and prioritize a portfolio of multiple DER types across a utility service territory.

In analyzing portfolios of multiple DER types across a utility service territory, it is important to first establish a single primary cost-effectiveness test that can be used for all DER types. Then, it is useful to articulate the jurisdiction's DER planning objectives, which can include, for example, one or some combination of: implement all cost-effective DERs; implement the lowest-cost DERs; maximize capacity benefits from DERs; encourage a diverse range of DER technologies; encourage customer equity; achieve GHG or electrification goals at lowest cost; and avoid unreasonable rate impacts.

Utilities and others can present the BCA results for DER portfolios in ways that facilitate comparison across DER types, such as:

- DERs can be ranked by benefit-cost ratios or net benefits to indicate the most cost-effective resources.
- Levelized DER costs can be used to directly and consistently compare costs across different DER types.
- Levelized net cost curves can be used to compare and prioritize DERs according to key parameters such as $/ton GHG reduced.
- Multiple cost-effectiveness tests, in addition to the JST, can provide additional information when analyzing portfolios of multiple DER types.

Figure S-4. Example DERs Sorted by Net Benefit

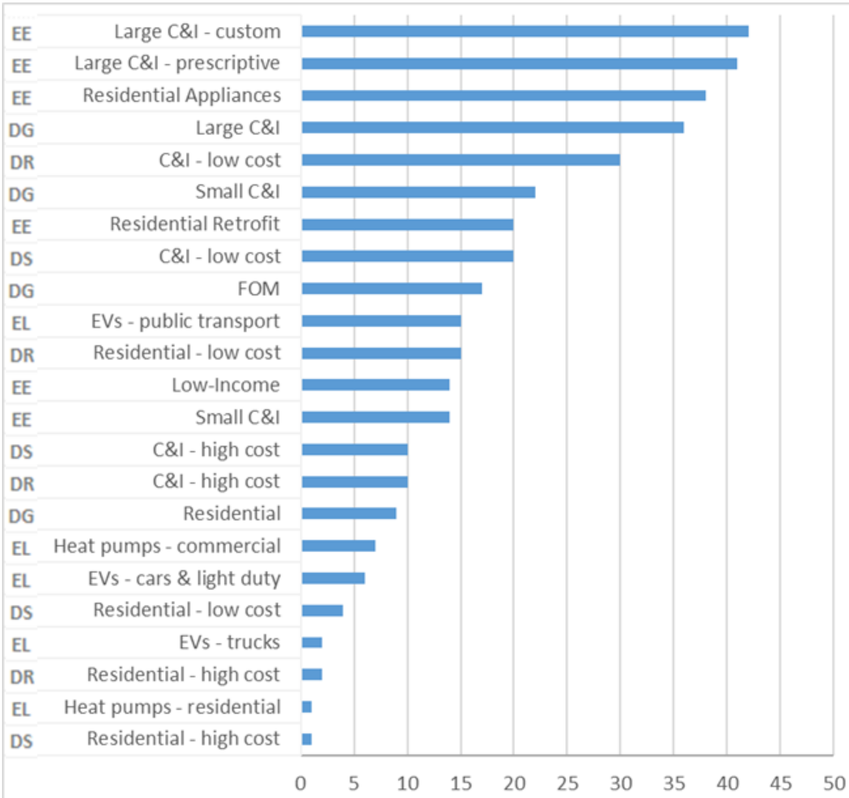


Figure S-4 presents a list of hypothetical DERS sorted by the net benefits that they provide. This information could be used to identify those DERs that warrant utility support or funding in order to achieve the greatest net benefits for a given level of funding. A similar approach could be used to prioritize BCRs by their benefit-cost ratios, or to prioritize DERs for within a given rate impact cap.

In some cases, a jurisdiction may prefer to invest in a diverse range of DER types on the basis that all DER types contribute benefits in different ways and there is value in promoting a diversity of technologies, as well as reducing associated system risk. In such a case, regulators might decide to support a minimum amount of each type of DER. This could be achieved by sorting the DER types by net benefits or benefit-cost ratios and selecting the lowest cost options for each type of DER.

Dynamic System Planning

Utilities have conducted traditional distribution system planning for many years to determine how to best to build and maintain the distribution grid. The focus of this practice has been on providing safe, reliable power through the distribution grid at a low cost. It typically has not accounted for DERs as alternatives to traditional distribution system technologies. However, the scope of utility system planning is expanding to manage the increasing complexity of the electricity system, while addressing evolving state policy objectives, changing customer priorities, and increased DER deployment. The manual provides an overview of evolving advanced planning practices that can allow utilities to more effectively and dynamically optimize DERs using *dynamic system planning*.

Table S-9 summarizes several different types of planning practices used by electric and gas utilities. It presents practices according to whether they are used by distribution-only or vertically integrated utilities, and it shows what elements of the utility system are accounted for by each type of practice.

Each type of planning practice uses some form of BCA for comparing and optimizing different resources. Each practice is a type of dynamic system planning described above, where the resources of interest are optimized relative to a dynamic set of alternative resources.

Table S-9. Types of Dynamic System Planning Practices

Type of Utility System	Planning Practice	Planning Practice Accounts for: Distribution System	DERs	Transmission System	Utility-Scale Generation
Distribution-only & vertically integrated	Traditional distribution planning	✓	-	-	-
	Integrated distribution planning (IDP)	✓	✓	-	-
Vertically integrated	Transmission planning	-	-	✓	-
	Integrated resource planning (IRP)	-	✓	-	✓
	Integrated grid planning (IRP)	✓	✓	✓	✓

Dynamic system planning practices have evolved in recent years to optimize DERs and maximize their value to the system. These include integrated distribution planning (IDP) for distribution-level planning only and integrated grid planning (IGP) for full-system planning.

Appendices

Table S-10 summarizes the appendices that provide further detail on some NSPM topics that warrant additional explanation.

Table S-10. Guide to Appendices

Part V	Appendices	
Appendix A	Rate Impacts	Describes the difference between cost-effectiveness and rate impact analyses, as well as the role of rate, bill, and participation analyses
Appendix B	Template NSPM Tables	Tables that can be used by jurisdictions to document applicable policies and relevant benefits and costs to inform their BCAs
Appendix C	Approaches to Accounting for Relevant Impacts	Provides guidance on options to account for relevant benefits and costs, including hard-to-quantify impacts and non-monetary impacts
Appendix D	Presenting BCA Results	Provides guidance on presenting results in a way that is most useful for making cost-effectiveness decisions
Appendix E	Traditional Cost-Effectiveness Tests	Summarizes the commonly used traditional cost-effectiveness tests from the *California Standard Practice Manual*
Appendix F	Transfer Payments and Offsetting Impacts	Provides guidance on impacts that appear to be both a benefit to one party and a cost to another party, thereby cancelling each other out
Appendix G	Discount Rates	Describes ways to determine discount rates that are consistent with the jurisdiction's applicable policy goals
Appendix H	Energy Efficiency—Additional Guidance	Describes how to address free-riders and spillover effects where net savings are used; and treatment of early replacement measures